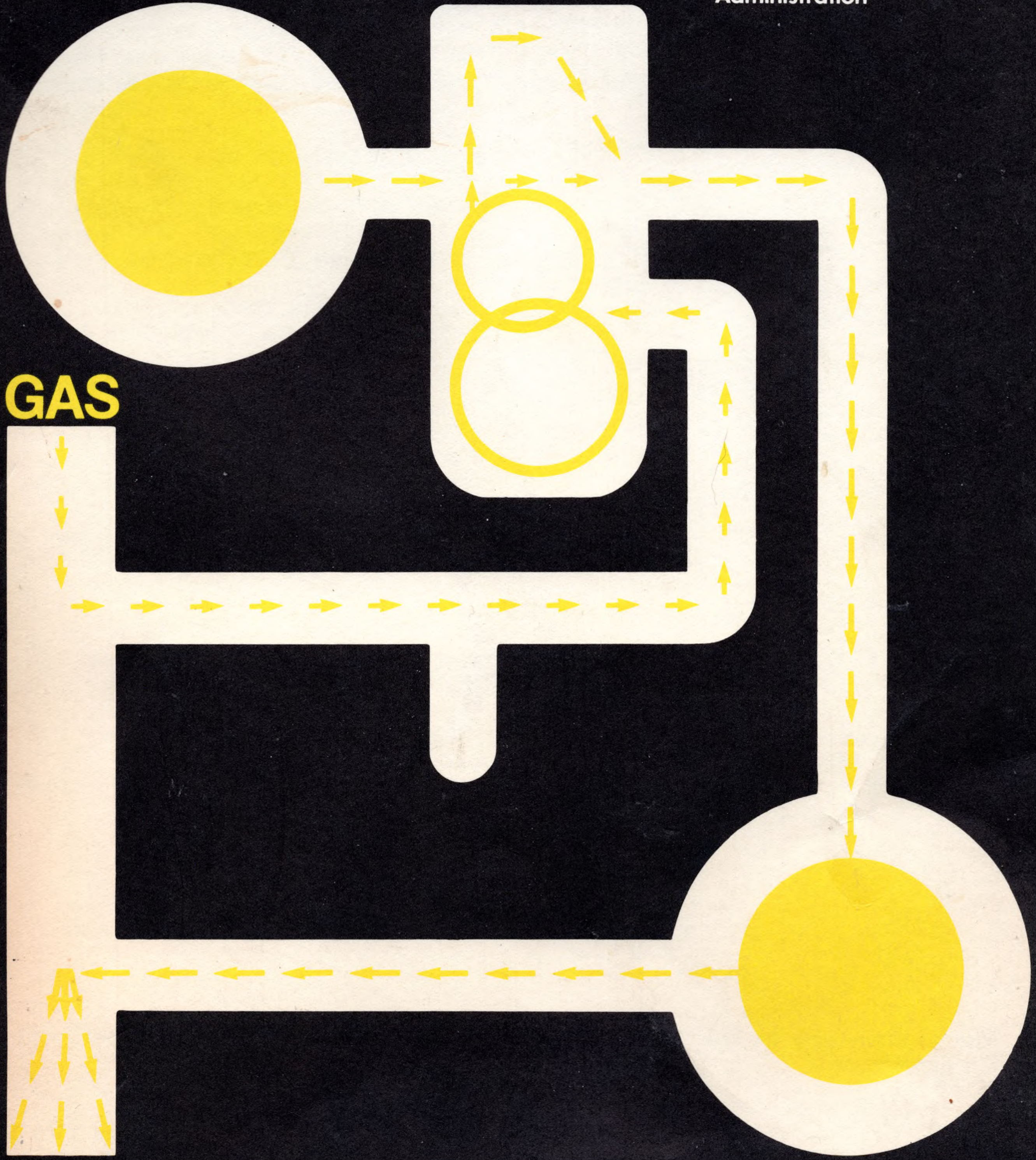
Guidance Manual for

Operators of Small Gas Systems

U.S. Department of Transportation

Research and Special Programs Administration



This Guidance Manual was revised under the sponsorship of the Department of Transportation, and its dissemination is encouraged in the interest of information exchange. The Manual utilizes comments and sources representing the best opinion of the subject at the time of its preparation. However, it should not be assumed that all acceptable safety measures and procedures are mentioned. The reader is referred to the Code of Federal Regulations (49 CFR, Parts 190-195) for additional pipeline safety requirements.

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Revised 1985

TO THE READER

The United States Department of Transportation promotes the safe transportation by pipeline of hazardous materials. Evidence of our commitment to safety is this guidance manual for operators of small gas systems. This manual was developed to provide a broad and general overview of your compliance responsibilities under federal pipeline safety regulations. It has been designed for the non-technically trained person who operates a master meter system, a liquified petroleum gas (LP-Gas) system with ten or more customers, a small municipal system, or a small independent system.

The Federal government recognizes that most operators of small gas system have not had extensive training in proper operation and maintenance of a gas system. In addition, many of the regulations are in technical language because they cover both large and small gas system operations. Therefore, this manual attempts to simplify the technical language of the regulations.

For certain critical regulations, the manual gives specific details for methods of operation and selection of materials which will meet the pipeline safety standards requirements. Often the material given is only one of several allowable options available to you the operator. The material selected is the material that is most commonly used in gas systems at the present time. Our aim is to provide sufficient basic information so that you as the operator will be able to ascertain your compliance capabilities and where to seek technical help. Comments, suggestions, and/or corrections should be mailed to: U. S. Department of Transportation, Information Services Division, 400 Seventh Street, S.W., Washington, D. C. 20590.

It is hoped that this document will assist you in achieving and maintaining a safe and efficient gas system. The result will be to enhance public safety --- an essential goal for the Department.

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INTRODUCTION

The Natural Gas Pipeline Safety Act of 1968 required the Department of Transportation (DOT) to develop and enforce minimum safety regulations for the transportation of gases by pipeline. These regulations became effective in 1970 and the Materials Transportation Bureau of DOT is charged with their enforcement. They are published in Title 49, Code of Federal Regulations, Parts 190, 191, and 192.

This pipeline safety code applies to:

- gas utilities (private, public, and municipal),
- operators of housing developments and mobile home parks served by natural gas master meters,
- liquefied petroleum gas (LP-Gas) systems that supply ten or more customers from a single source, and
- any portion of a LP-Gas system located in a public place, such as a highway.

The pipeline safety code says that operators of all gas systems must:

- deliver gas safely and reliably to customers,
- provide training and written instruction for employees,
- establish written procedures to minimize the hazards resulting from gas pipeline emergencies, and
- keep records of inspection and testing.

It is very important that you meet your responsibilities under the code because operators who do not comply may be subject to civil penalties, compliance orders, or both. If the hazards warrant it, a "Hazardous Facility Order" may be issued that could shut down your system.

In some cases state agencies have assumed the responsibility for enforcing pipeline safety standards for operators within their state. The state agency is allowed to adopt additional or more stringent safety standards for intrastate pipeline transportation as long as such standards are compatible with the federal minimum standards. If a state agency has not taken safety jurisdiction over an intrastate operator, the federal government retains jurisdiction.

Operators should check with the agency in their state (listed in Appendix A) to determine:

- o whether a state agency has safety jurisdiction over their specific type of gas system,
- o whether the state agency has additional pipeline safety requirements, other than the federal standards, and
- o the inspection and enforcement procedures of the state agency.

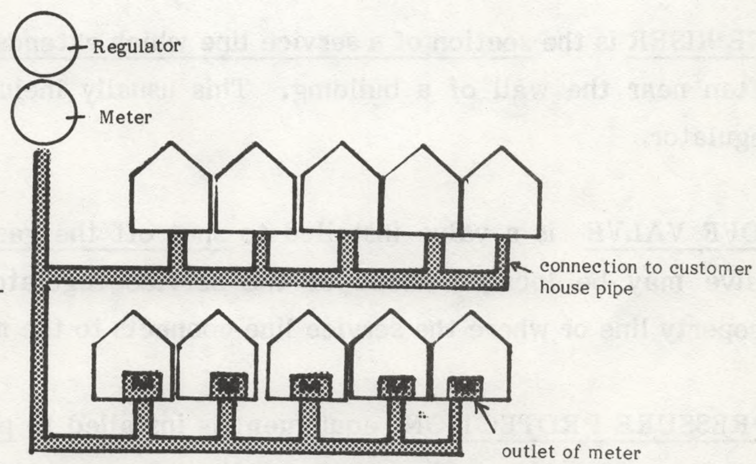
DEFINITIONS AND TERMS

To understand this manual, you will need to know the meaning of some commonly used terms in the natural gas and LP-Gas industry. Look over this list and read carefully any definition of a word when you may not be sure of its meaning.

GAS OPERATOR is a person who engages in the transportation of gas. A gas operator may be a gas utility company, a municipality, or an individual operating a housing project, apartment complex, condominium, or a mobile home park served by a master meter.

MASTER METER SYSTEM means a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means such as by rent.

In this diagram the LP-Gas tank or natural gas pipeline is not part of master meter system. It is the responsibility of the supplier.



Master meter operator is responsible for shaded portion. Operator must comply with CFR Title 49, Part 191 & 192.

NATURAL GAS is a non-toxic, colorless fuel, about one third lighter than air. Gas burns only when mixed with air in the right proportion and ignited by a spark or flame. (Figure D-4, Appendix D.) Gas, in its natural state, may not have an odor.

LIQUIFIED PETROLEUM GAS (LP-GAS or LPG) is gas in a liquid state in the supply tank, but it is vaporized at the tank's outlet then distributed in a gaseous state. There are two properties of LP-Gas that you should know: it expands when the temperature rises, and it is heavier then air. The importance of these two properties to LP-Gas users is explained further in Appendix B.

SERVICE LINE is a gas distribution line that transports gas from a common source of supply to a customer's meter, or to the connection to a customer's piping if the piping is farther downstream, or if there is no meter.

MAIN is a distribution line that serves as a common source of supply for more than one service line.

PIPELINE means all parts of those physical facilities through which gas moves in transportation. This includes pipe, valves, and other items attached to pipe, meter stations, regulator stations, delivery stations, holders, or fabricated assemblies.

CUSTOMER METER is a device that measures the volume of gas transferred from an operator to the consumer.

SERVICE REGULATOR is a device designed to reduce and limit the gas pressure to the consumer.

SERVICE RISER is the section of a service line which extends out of the ground and is often near the wall of a building. This usually includes a shut-off valve and a regulator.

SHUT-OFF VALVE is a valve installed to shut off the gas supply to a building. The valve may be located ahead of the service regulator or below ground at the property line or where the service line connects to the main.

OVERPRESSURE PROTECTION equipment is installed to prevent pressure in a system from exceeding the maximum allowed limit for operating the system safely.

PRESSURE REGULATING/RELIEF STATION automatically reduces and controls the gas pressure downstream from a high pressure source of gas into a system operating at a lower pressure. It includes any enclosures, relief devices, and ventilating equipment, and any piping and auxiliary equipment (such as valves, regulators, control instruments, or control lines.)

PSIG - is an abbreviation for pounds per square inch gage pressure. You can read more on PSIG in Appendix H.

MAOP - is an abbreviation for maximum allowable operating pressure. This is established by design, past operating history, pressure testing, and pressure ratings.

CORROSION - is the rusting of a metal pipe. This is caused by a electro-chemical reaction that takes place between metallic pipe and its surroundings. As a result, the pipe deteriorates and will eventually leak. This underground corrosion can be retarded with cathodic protection.

CATHODIC PROTECTION - is a procedure by which underground metallic pipe is protected against corrosion. It is a method for controlling the corrosion or deterioration of steel pipe and connected metallic equipment through the use of electrolysis. Some basic theory, concepts, and practical considerations for cathodic protection are contained in Appendix F. The federal requirements that an operator must meet are in Appendix E.

OPERATING AND MAINTENANCE PLAN (O & M PLAN) - is a plan that the federal government requires you the operator to write outlining the procedures you follow to operate and maintain a safe system. The operating and maintenance requirements that should be in your plan are listed in Chapter I of this manual. A discussion of the pipeline safety regulatory requirements which should be included in your plan are discussed in Appendix E.

49 CFR - refers to the Code of Federal Regulations, Title 49, the document that contains the actual regulations you must follow. The title number refers to a particular volume. Part 191 or Part 192 refers to particular parts in the volume.

COMMONLY ABBREVIATED ORGANIZATIONS

ANSI - American National Standards Institute, 1430 Broadway, New York, New York 10018, formerly the United States of America Standards Institute (USASI.) All current standards issued by USASI and ASA have been redesignated as American National Standards and continue in effect.

API - American Petroleum Institute, 2101 L Street, N.W., Washington, D.C. 20037 or 211 North Ervay, Dallas, Texas 75201.

ASME - The American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, New York 10017.

ASTM - American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103.

DOT - United States Department of Transportation, 400 Seventh Street, S.W., Washington, D.C. 20590.

MSS - Manufacturers Standardization Society of the Valve and Fittings Industry, 5203 Leesburg Pike , Suite 502, Falls Church, Virginia 22041.

MTB - Materials Transportation Bureau. This is the federal agency in DOT which is responsible for development and enforcement of the pipeline safety code. For addresses of regional offices, see Appendix A.

NACE - National Association of Corrosion Engineers, P.O. Box 218340, Houston, Texas 77218.

NFPA - National Fire Protection Association, Batterymarch Park, Quincy, Massachusetts 02269.

CHAPTER I

REPORTING AND PLANS REQUIRED BY THE FEDERAL GOVERNMENT

ALL O&M PLANS MUST CONTAIN THE FOLLOWING COMPONENTS:

IN THIS CHAPTER. . .

The federal government requires every gas operator to telephone a report of any "incident" (as defined below) and to develop, follow and maintain records of an Operation and Maintenance (O&M) Plan and an Emergency Plan. This chapter describes the "incident" report and the Plans. In some instances you may wish to refer to the referenced appendices at the end of this manual for more in-depth information. The appendices also provide assistance on how to obtain a consultant or advice from other knowledgeable sources. Remember to check with your own state agency (in Appendix A) for any additional state requirements.

"INCIDENT" REPORT (Formerly called leak report)

TELEPHONE TOLL FREE - (800) 424-8802

WASHINGTON, D.C. (202) 426-2675

24 HOURS EVERY DAY

You are required to telephone an "incident" report at the earliest possible moment if any one of the following events should occur: (49 CFR 191.3 and 191.5)

1) There is a release of gas from a pipeline, or of liquified natural gas (LNG) or gas from a LNG facility,

AND

there is a death or personal injury requiring hospitalization or there is estimated property damage, including the cost of gas lost, of the operator or others, or both, of $50,000 or more.

2) There is an emergency shutdown of a liquified natural gas (LNG) facility.

3) There is an event that is significant in the judgment of the operator, even though it was not described in paragraphs (1) or (2) above.

When in doubt CALL: Toll Free - 800-424-8802

Washington, D.C. (202) 426-2675

This telephone report of a serious incident should include:

- o Identity of reporting operator (housing authority, mobile home park name),
- o Name and phone number of individual reporting the incident,
- o The location of the leak (city, county, state, and street address),
- o The time of the leak (date and hour),
- o The number of fatalities and personal injuries, if any,
- o Type and extent of property damage, and
- o Description of the incident.

An incident requiring a telephone report must be followed up with a written report unless the report is made by a small operator such as a master meter operator, a condominium or cooperative owner or an owner of rental property such as an apartment building. See Appendix N for written report instructions. (49 CFR 191.9)

The previous edition of this Manual referenced a written annual report that was to be filed by all natural gas operators and certain liquid petroleum gas operators. The annual report is no longer required from master meter operators, petroleum gas system operators serving fewer than 100 customers from a single source, or liquified natural gas facilities. (49 CFR 191.11)

OPERATION AND MAINTENANCE PLAN

Prior to 1979 gas operators were required to file an Inspection and Maintenance (I & M) plan. However since the Pipeline Safety Act was amended, the I & M plans are no longer required to be filed with the federal government. Instead, each individual state agency determines its policy for filing I & M plans. If you are subject to state jurisdiction, check with your state for its filing requirements. A listing of the address and telephone number of all state agencies is in Appendix A.

If your state does not have safety jurisdiction over your type of gas operations, MTB/Office of Operations and Enforcement (OOE) is responsible for the enforcement of

the pipeline safety regulations. (The five federal regional offices of the MTB/OOE are also in Appendix A.)

NOTE: MTB recommends that if you had an I & M plan previously, or if your state requires one, it be combined with the Operation and Maintenance (O&M) plan. The combined plan must be continually updated and available to your operating personnel and, upon request, to appropriate federal or state inspectors.

As an operator you should recognize that it is important to maintain a proper and organized O&M plan, not only for compliance with federal law, but as protection and defense against any civil suit that might be filed for damages caused by your gas system.

An O&M plan is required of all gas operators by the pipeline safety standards (49 CFR 192.603). The O&M plan must be written down. It must contain the steps which must be followed to accomplish the required operational and maintenance procedures. The balance of this chapter outlines thirteen of these procedures (lettered A-M) that must be covered in your O&M plan if you are a master meter operator. Five additional procedures (lettered N-R) may apply to some operators of small public/private utilities, but most likely will apply only to larger or more complex systems such as those operated by a small municipality. In addition to an O & M plan, small operators (other than LP gas and master meter operators such as condominiums, co-ops and rental apartment complexes) must maintain a damage prevention program. See 49 CFR 191.614.

ALL O&M PLANS MUST CONTAIN THE FOLLOWING COMPONENTS:

A. INSTRUCTIONS FOR EMPLOYEES

These instructions must cover operating and maintenance procedures which MUST BE FOLLOWED during normal operations and while making repairs (49 CFR 192.605(a)).

B. EMERGENCY PROCEDURES

You must include specific procedures which must be followed to ensure the greatest public safety, during an emergency, or because of extraordinary construction or maintenance requirements (49 CFR 192.605(c).

C. LINE MARKERS

Your O&M plan must specify locations where you will mark pipe locations. The following are the federal requirements: (49 CFR 192.707)

Buried distribution pipelines. A line marker must be placed and maintained as close as practical over each buried distribution main at each crossing of a highway, street, or railroad. A line marker must also be placed wherever necessary to identify the location of the main to reduce the possibility of damage or interference. Line markers are not required for buried mains in Class 3 or 4 locations where it can be shown to be impractical, or where you participate in a damage prevention program (such as "one call" or "call before you dig" system.)

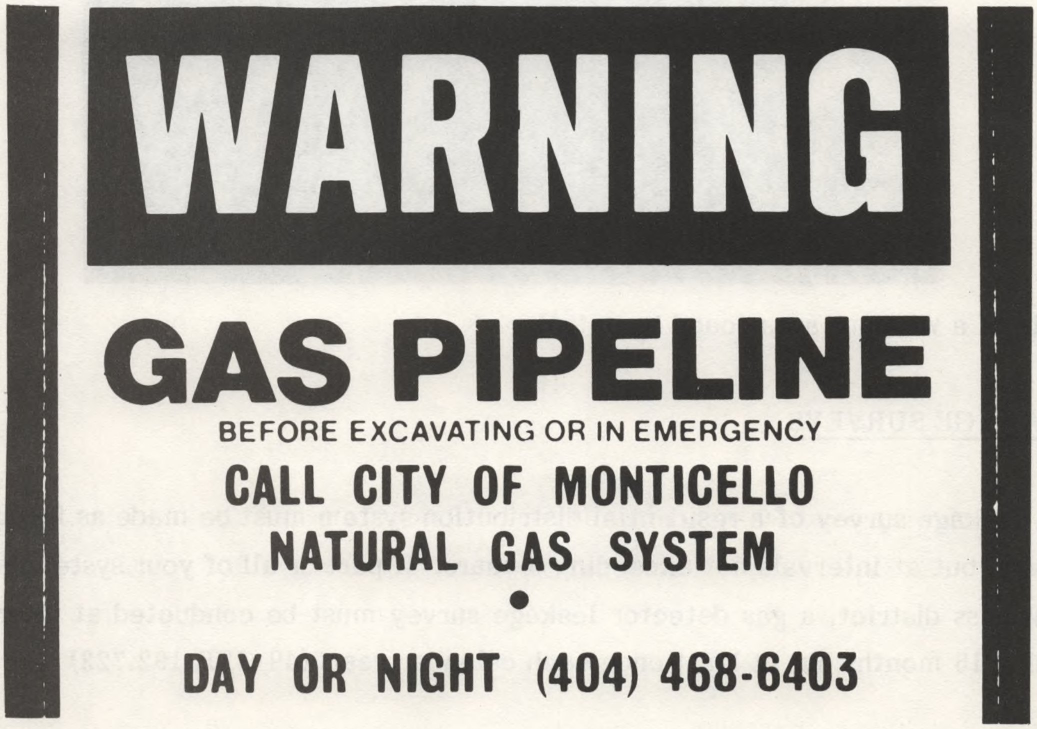
Distribution pipelines above ground. Line markers must be placed and maintained along each section of a main that is located above ground in an area accessible to the public. (An example would be an unsecured master meter set or regulator station.)

Markers. The following must be written legibly on a background of sharply contrasting color on each line marker.

1. The word "Warning," "Caution," or "Danger" followed by the words "Gas (or name of gas transported) Pipeline." Letters must be at least one inch high with one-quarter inch stroke.

2. The name of the operator and the telephone number (including area code) where the operator can be reached at all times. (49 CFR 192.707). (See Figure I-1)

FIGURE I-1

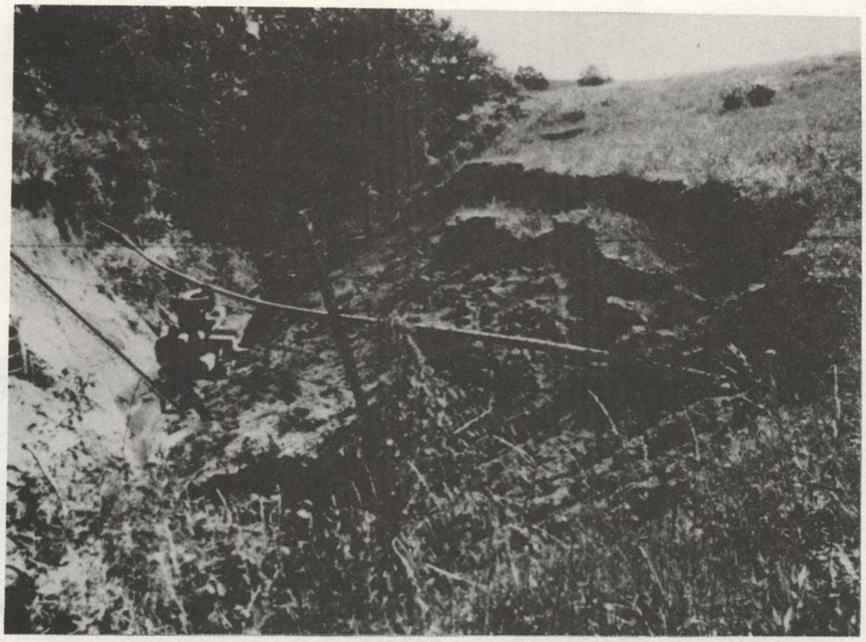


Pipeline marker which meets the Federal requirements.

D. PATROLLING

Operators must include in their plan provisions for patrolling mains located in places or on structures where anticipated physical movement or external loading (weight, traffic) could cause failure or leakage (49 CFR 192.721). These include areas such as: pipe located on bridges, waterways, land slide areas, areas susceptible to earth subsidence (cave ins), or an area of construction activity. Patrolling of these mains must be at intervals not exceeding 4 1/2 months but at least four times each calendar year. (Appendix C, Form 4) Patrolling can be done by walking along the pipeline and observing factors affecting safe operation.

FIGURE I-2



Example of a washout area found by patrol

D. LEAKAGE SURVEYS

A leakage survey of a residential distribution system must be made as frequently as necessary, but at intervals not exceeding 5 years. If part or all of your system is located in a business district, a gas detector leakage survey must be conducted at intervals not exceeding 15 months but at least once each calendar year. (49 CFR 192.723)

A suggested leakage survey schedule would be as follows:

1. A leakage survey must be conducted over an entire residential pipeline system at intervals not exceeding 5 years, it may be appropriate for operators to increase the frequency of surveys based upon factors such as:

   (a) Material makeup of system. Certain materials may develop a higher than average leakage rate (for example, unprotected bare steel, PVC plastic pipe, extruded tubing, cast iron with lead joints, and coated steel pipe not under cathodic protection.)

   (b) Age of pipe (over 20 years) and corrosive soil environment.

(c) Operating pressures (over 60 psig.)

(d) Pipe having a previous history of excessive leakage and the cause(s) has not yet been eliminated.

(e) Pipeline location. Pipelines in, under, or near buildings, especially schools, churches, hospitals, or other buildings having a high concentration of people. (See Appendix C, Form 5)

(f) Pipeline located in areas of construction, blasting, or recent heavy weight traffic. Pipe located in crawl spaces under apartment buildings or mobile homes.

(g) Service lines in or under buildings and meters in buildings.

Based on the above factors, operators should designate areas in a system which require more frequent surveys. Annual leakage surveys conducted with a flame ionization (FI) or combustible gas indicator (CGI) may be appropriate if you have one or more of the above conditions. <u>For LP-Gas systems surface detection methods are not acceptable.</u>

Available openings are water, sewer, electric, telephone, manholes, cracks in payment, vaults, and hollow walls (cinder block construction) in areas near gas piping. Also, see Appendix B for details about gas indicators and types of leakage surveys.

When conducting these surveys, it is a good policy to check for leaks near the gas pipe entrance, both inside and outside the buildings.

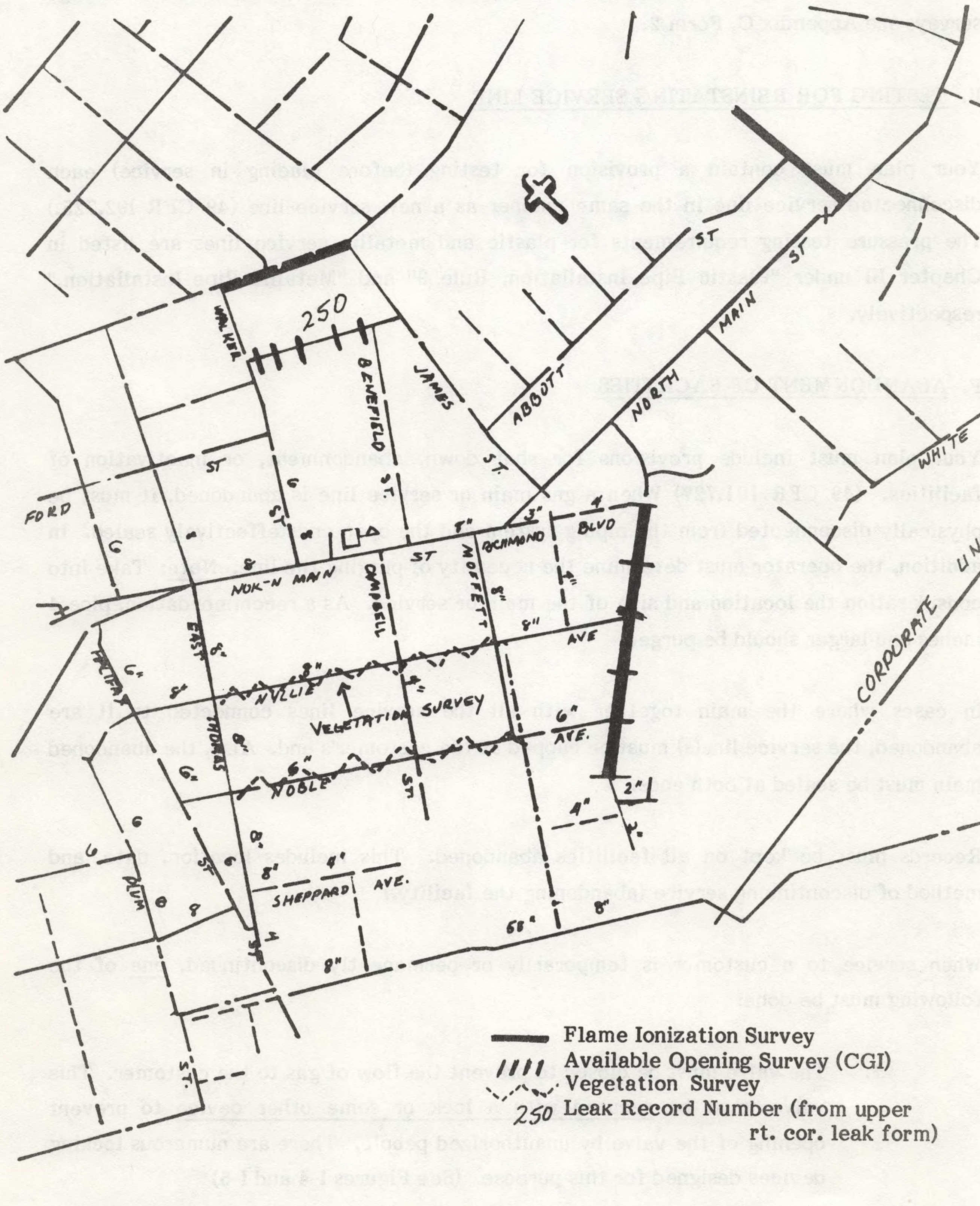
2. Heavily populated areas require more frequent leakage surveys. If your gas system is included in a business district, a leakage survey [utilizing FI or CGI equipment at available openings] must be conducted in the central business district and shopping centers at intervals not exceeding 15 months but at least once each calendar year. Areas surveyed should be marked on a map of the distribution system. See Figure I-3. All leaks discovered must be recorded. Sample forms are in Appendix C, Form 2.

3. When a leak is discovered, it must be investigated to determine if a hazard exists. If a hazardous condition is found, immediate action must be taken. The operator must protect life and property until the conditions are no longer hazardous. ALL leaks found should be classified as soon as located. If a leak is hazardous it must be repaired, immediately. As a guide for classifying leaks, operators may want to include the ASME "Leak Classification Guide and Action Criteria" in their O&M plan. This ASME Guide Material is contained in Appendix B.

4. Vegetation surveys should be conducted annually during the growing season. These surveys can be conducted by meter readers or other maintenance personnel. Appendix B contains some details about what to look for in vegetation surveys. Leaks discovered should be recorded on Form 3, Appendix C.

5. Annually, a map of the distribution system should be marked (or color coded), to show leak surveys conducted, and the areas tested. Indicate the approximate location of each leak found. Annotations may be made in accordance with Figure I-3.

Figure I-3



Sample Distribution Map Showing How Leak Surveys Are Recorded

See Appendix B for detail about gas detection equipment and recommended practices to follow when conducting a leakage survey. For sample records for leakage surveys see Appendix C, Form 2.

E. TESTING FOR REINSTATING SERVICE LINE

Your plan must contain a provision for testing (before placing in service) each disconnected service line in the same manner as a new service line (49 CFR 192.725.) The pressure testing requirements for plastic and metallic service lines are listed in Chapter III under "Plastic Pipe Installation, Rule 9" and "Metallic Pipe Installation," respectively.

F. ABANDONMENT OF FACILITIES

Your plan must include provisions for shut down, abandonment, or inactivation of facilities. (49 CFR 191.727) When a gas main or service line is abandoned, it must be physically disconnected from the piping system and the open ends effectively sealed. In addition, the operator must determine the necessity of purging the line. Note: Take into consideration the location and size of the main or service. As a recommendation, pipe 4 inches and larger should be purged.

In cases where the main together with all the service lines connected to it are abandoned, the service line(s) must be capped at the customer's end. Also, the abandoned main must be sealed at both ends.

Records must be kept on all facilities abandoned. This includes location, date, and method of discontinuing service (abandoning the facility.)

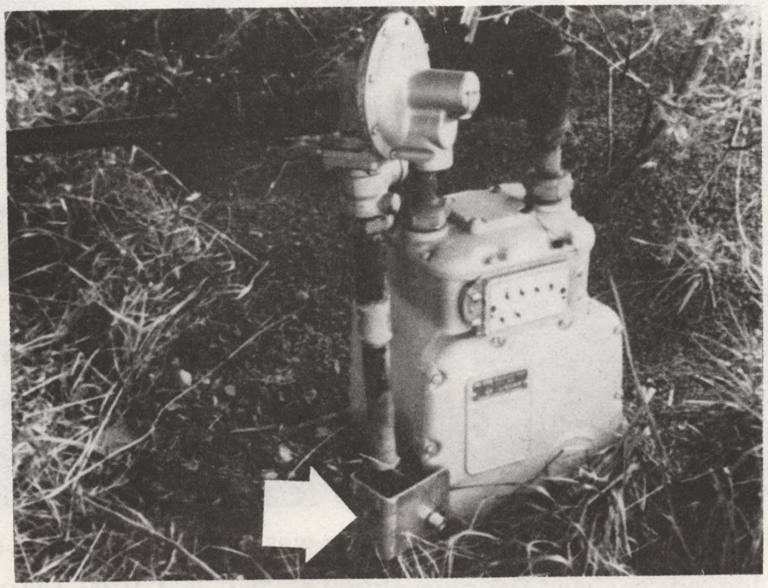
When service to a customer is temporarily or permanently discontinued, one of the following must be done:

1. The valve must be closed to prevent the flow of gas to the customer. This valve must be secured with a lock or some other device to prevent opening of the valve by unauthorized people. There are numerous locking devices designed for this purpose. (See Figures I-4 and I-5)

2. A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

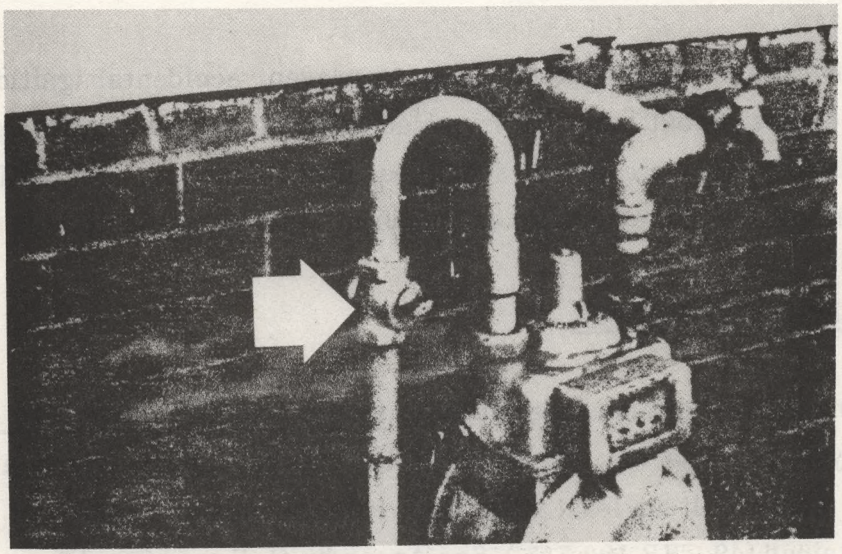
3. The customer's piping must be physically disconnected from the gas supply and the open ends sealed (49 CFR 192.727). (Figure I-6)

FIGURE I-4



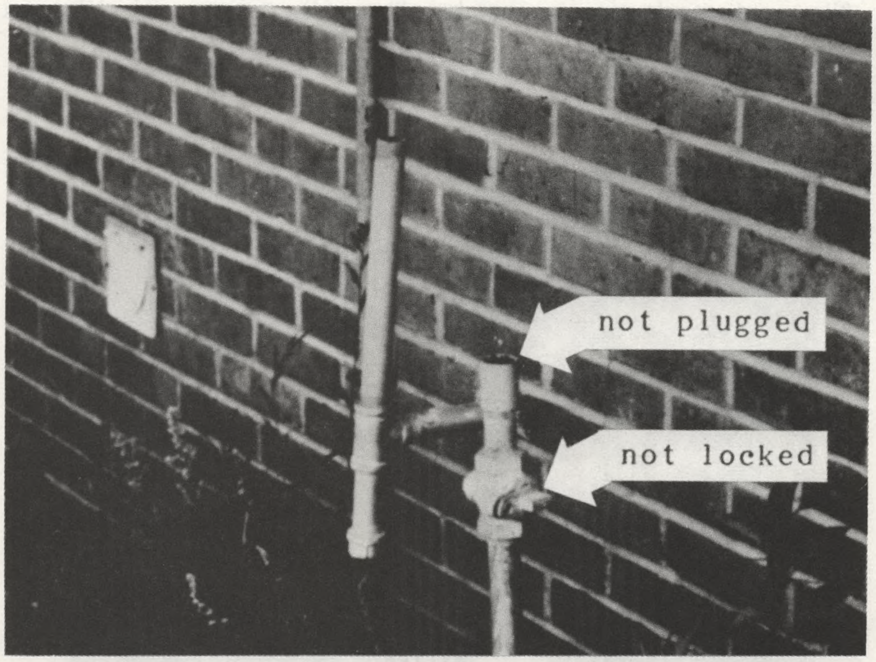
Example of a meter valve which has been locked to prevent the opening of the valve by unauthorized people.

FIGURE I-5



This is an example of a service that has been shut off (note position of meter valve) but not locked to prevent opening. This DOES NOT meet the pipeline safety standards requirements.

FIGURE I-6



This is an example of a service where the meter was removed, but the shut off valve on the riser was not locked, nor was the pipe plugged. This is A VIOLATION of the pipeline safety standards requirements.

H. ACCIDENTAL IGNITION OF GAS

Provisions in the plan must be made to prevent accidental ignition of gas. Gas alone is not explosive but when it is mixed with air, it can ignite or explode with tremendous force. Every precaution should be taken to prevent unintentional ignition of gas. When venting gas into air, a fire extinguisher must be available. (49 CFR 192.751.)

I. KEY VALVES MAINTENANCE

Provisions in the plan must be made to assure that key valves are operable in the distribution system. The key valves must be checked and serviced at intervals not exceeding 15 months but at least once each calendar year. Records of this inspection must be maintained (49 CFR 192.747.) See Appendix C, Forms 8 and 9.

The valves that are considered key valves are the valves needed to shut down the system, or part of the system, in case of an emergency. For small LP-Gas and master meter systems this may involve only one or two valves. Usually, operators do not consider service line valves as key valves that require an annual maintenance check.

Steps to Take in Determining Key Valves

Determine the location of all valves on mains. (You might plot them on your system map and detail sketches with dimensions to other permanent structures.)

Determine a key valve by the degree of importance to system operation. The following types of valves can be key:

- Control valve(s) at each pressure regulator station
- Primary feed(s) to business districts
- All valves on mains within a business district

Other valves may be considered key if they meet the following criteria:

1. Reasonable for sectionalizing plan. Consider:
   - Number of customers
   - System pressure
   - Volume of gas which could escape
   - Environment (near school, soil condition, construction activity, etc.)
   - Response time/valve accessibility

2. Necessity - based on system operating history:
   - Excessive leakage
   - Corrosion problem
   - Pipe breakage problem
   - Pressure problem

J. MEASURING THE ODORIZATION OF GAS

Master meter - natural gas operators. Operators purchasing natural gas from a natural gas utility company must make provisions in their O&M plan for measuring odor. Operators must verify that a person with a normal sense of smell can detect the gas in air at one-fifth the lower explosive limit. The lower explosive limit for natural gas is approximately 4 percent natural gas-in-air by volume. Therefore, you must verify that the gas odor can be detected at approximately one(1) percent gas-in-air (i.e. 1/5 x 4% = approximately 1%.)

How to comply:

- o Have the gas company that sells you the gas verify by either records or tests, that the gas being sold to you meets the above criteria.

- o Have a qualified person or the gas utility company or transmission company run an odorometer test of the gas in your system.

- o Note: Periodic "sniff tests" can be a guide in determining odorization levels even though they do not replace the need to maintain oderant usage records or perform odorometer tests. To conduct "sniff tests" the operator should ask tenants, especially heavy smokers and the elderly, at various locations to smell the gas at an open valve or gas oven burner. If they can not detect its odor, you should contact the gas supplier. This sniff test can also be accomplished during meter change outs or other maintenance work. Make sure you keep records of these tests, including dates, names, and locations. (See Appendix C, Form 11)

NOTE: These tests should be run at the ends of the system, when possible.

LP-Gas operators should make provisions in their O&M plan for the following:

- o Verify that the odorant in the gas purchased meets the requirements in Appendix I. This can often be done by retaining copies of the bills of lading from the supplier of gas as evidence of odorant.

- o Have provisions in your O&M plan for periodic "sniff tests" for gas in system. This can be accomplished by having employees and customers or tenants "sniff" gas at an open valve or gas burner. A sniff test can also be performed during work, such as meter change outs, or other maintenance work. Make sure you keep records of these tests, including dates, names, and locations. (See Appendix C, Form 11)

K. CATHODIC PROTECTION

If you have metallic pipes, provisions must be made in your O&M plan for cathodic protection. Your plan must include procedures for:

- o Implementing a corrosion control program. This must be under the direction of a person qualified by experience and training in pipeline corrosion control methods.

- o Ensuring cathodic protection and coating of a new steel pipe. (Appendix C, Form 1)

- o Ensuring cathodic protection of existing piping. (Form 14)

- o Examining exposed pipe. (Form 1)

- o Testing the effectiveness of cathodic protection each calendar year with intervals not exceeding 15 months. (Form 14)

- o Inspecting rectifiers, if used, at least 6 times a year, but with intervals not exceeding 2 1/2 months. (Form 15)

- o Checking atmospheric corrosion. (Form 13)

- o Maintaining records of all tests, surveys, or inspections.

Samples of all forms listed above are in Appendix C.

These requirements and "how-to-comply" are discussed in more detail in Appendix E. Some theory, practical concepts, and illustrations are contained in Appendix F.

L. LEAK REPAIRS - CONSTRUCTION

The O&M plan should contain provisions for leak repair and construction. These procedures will vary by system. Chapter IV of this manual gives some basic procedures and concepts that should be covered. Also see Appendix L.

M. EMERGENCY PLANS

All operators are required to have a written emergency plan. (49 CFR 192.615.) This plan can be part of your O&M plan. See Appendix D for guidance in preparing an emergency plan.

Helpful Hints: Place on the wall the "General Maintenance Schedule Chart," (Appendix C) as a helpful reminder of the required pipeline safety code inspections. Use the "Master Chart" (Appendix C) for the required record keeping of operation and maintenance work for your gas system.

N. UPRATING

THIS WILL NORMALLY NOT APPLY TO MASTER METER OPERATORS OR LPG OPERATORS.

Your system may require procedures for uprating (changing to higher pressure) from a low pressure distribution system to a higher pressure system. (49 CFR 192.605(d)). See Appendix G for details of a sample program. Procedures must be developed only if a pressure uprating is contemplated and included as part of the O and M plan.

O. INSPECTION OF REGULATOR STATIONS

THIS WILL NORMALLY NOT APPLY TO MASTER METER OPERATORS OR LPG OPERATORS.

If regulating stations are a part of your system, provisions must be made in the plan

for their inspection and/or testing. Many master meter systems will not have a regulating station. A simple definition of a regulating station is any pressure limiting device or regulator other than customer service regulator(s) installed in a gas system to control gas pressure. Simply put, if an operator does not lower the gas pressure from the local gas utility delivery pressure, or LP-Gas tank, except at a customer service regulator, this section does not apply.

For operators with regulation stations in system, provision must be made in the O&M plan to inspect and test both regulators and relief devices. Inspect at least once every calendar year but at intervals not to exceed 15 months to determine that they are:

- o mechanically in good condition,
- o adequate from the standpoint of capacity and reliability of operation,
- o set to function at the correct pressure, and
- o properly installed and protected from vehicle traffic, dirt, liquids, icing, or other conditions that might prevent proper operation (49 CFR 192.739.)

A record of this annual inspection must be kept. Sample forms are in Appendix C, (Forms 6, 7) You should inspect visually, do an operation check (stroke and lock up), and check the pressure at which the relief device and regulator are set. Keep watch for such problem areas as:

- o Distribution system pressure appears low,
- o Operating and maintenance history of station is not satisfactory,
- o Gas supply is dirty, or
- o Back-up safety devices are not operational.

If you have problems such as these, you may need technical help. Regulator disassembly or station redesign may be necessary. THE OPERATOR IS CAUTIONED NOT TO DISASSEMBLE REGULATORS, UNLESS OPERATOR HAS BEEN THOROUGHLY TRAINED (by the regulator manufacturer, its area representative, or consultant) in the proper steps to take in disassembly and reassembly of the particular regulator.

The operating and maintenance plan should include the names and telephone numbers of the people to contact for any situation in which outside assistance is

required. The operator should always keep and use the manufacturer's manual, diagrams, maintenance procedures for each particular regulator.

Appendix H contains some basic concepts about pressure regulation and relief devices.

P. TESTING OF RELIEF DEVICES AT REGULATOR STATIONS

THIS WILL NORMALLY NOT APPLY TO MASTER METER OPERATORS OR LPG OPERATORS.

Important Facts to Remember . . .

- If you are designing a new regulating station or replacing and/or making a major change to an existing station, the station must meet the design requirements contained in 49 CFR 192.195, 192.199, 192.201, and 192.203.

- Existing pressure limiting and regulating stations must be inspected and tested for operating condition at intervals not exceeding 15 months but at least once each calendar year. (49 CFR 192.739 and 192.743.)

- If your annual inspection shows existing relief device has insufficient capacity, you must replace or add a relief device to provide the required capacity.

- The stations should be protected from damage from outside forces (cars, trucks, falling objects.)

Usually the utility company, not the master meter operator, owns the relief devices at regulator stations. However, if you own one, provisions in your plan must be made for the testing of relief devices for capacity, if feasible. If not feasible, the calculation of capacity must be reviewed in intervals not exceeding one year. The operator must maintain a copy of this calculation. The test must show that the relief valve capacity is adequate for the system's maximum allowable operating pressure (MAOP.)

The regulations recognize two types of distribution systems: low pressure and other-than-low pressure. The relief capacity for low pressure must protect the customer's equipment from overpressurizing. The gas pressure in the main is approximately the same as the pressure provided the customer: usually 4 to 8 inches water column (2.5 to 5 oz per sq in) for natural gas and 7 to 11 inches water column (4 to 6 oz per sq in) for L. P. gases.

In pipelines other than a low pressure distribution system, the relief device must be set to operate such that:

- If the MAOP is 60 psig or more, the pressure may not exceed the MAOP plus 10 percent;

- If the MAOP is 12 psig or more, but less than 60 psig, the pressure may not exceed the MAOP plus 6 psig; or

- If the MAOP is less than 12 psig, the pressure may not exceed the MAOP plus 50 percent.

If testing reveals that the relief devices do not have adequate capacity, then a new or additional device must be installed.

Capacity must be checked for each separately controlled section of your system. (You must insure that the MAOP will not be exceeded downstream of the regulator station if the worst condition occurred--that is, if the regulator fails when fully opened.) Most small systems have only one MAOP, for all piping in the distribution system.

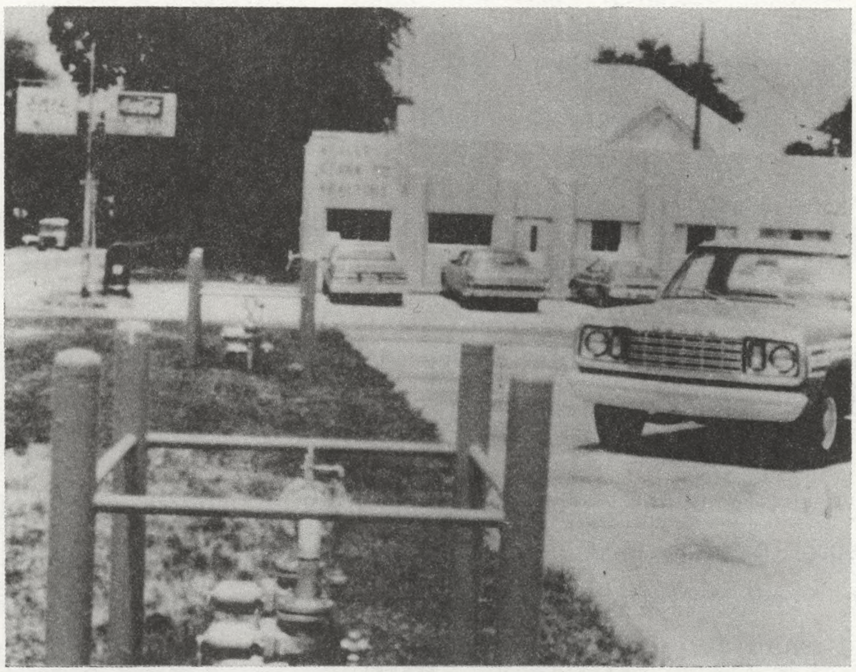
In sum, a combination of minimum customer usage and relief capacity must insure the MAOP will not be exceeded (except to the extent described above.)

To comply with this requirement many operators of small systems have a consultant analyze their gas system and make the required relief valve capacity calculations. If the analysis proves that the relief valve has adequate capacity, a copy of this calculation must be kept on file by the operator. If there has been no system change (i.e., change made to upstream regulators, such as different pressure, orifice, or type of regulator),

the calculation of capacity need only be reviewed and initialed on an annual basis. If a change is made, the new relief valve capacity calculations must be made and kept on file (49 CFR 192.743.) It is a good idea to keep this capacity calculation with your annual inspection record. Sample forms are in Appendix C, Forms 6 and 7.

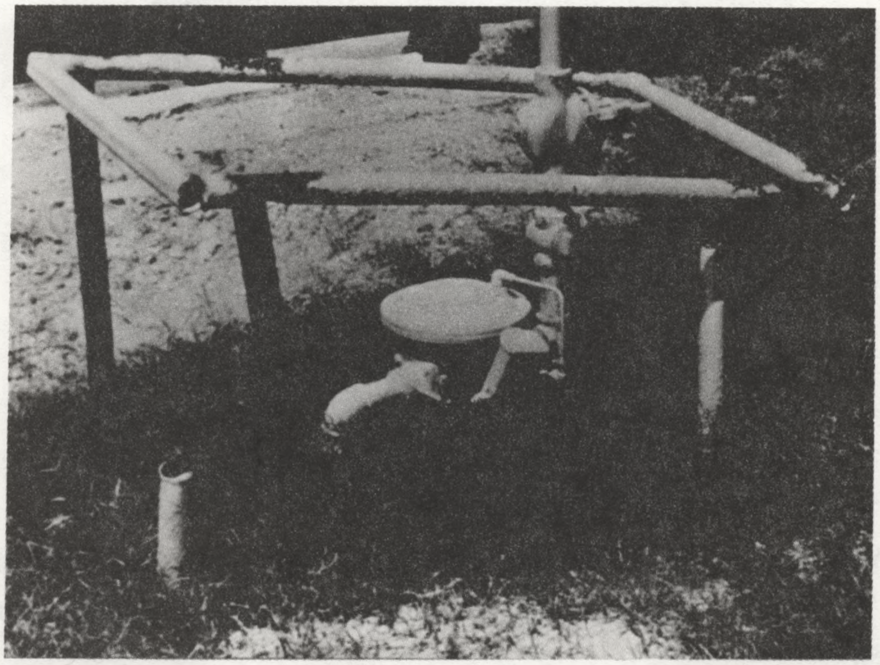
For other considerations for relief and regulating stations, see Appendix H.

Figure I-7



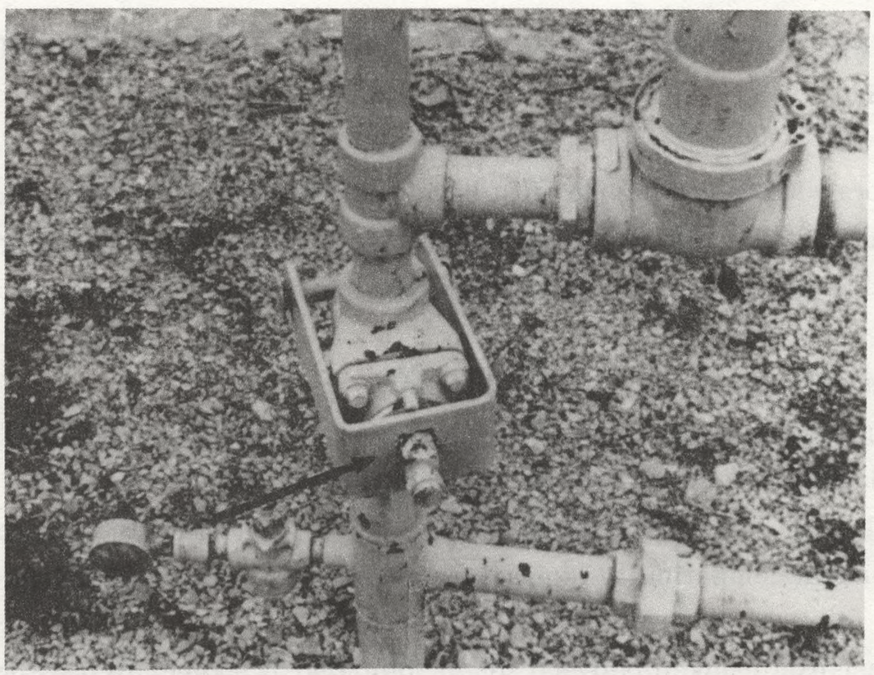
Example of a small, well-protected city district regulator station. Plastic pipe would not be acceptable for use as barrier pipe.

Figure I-8



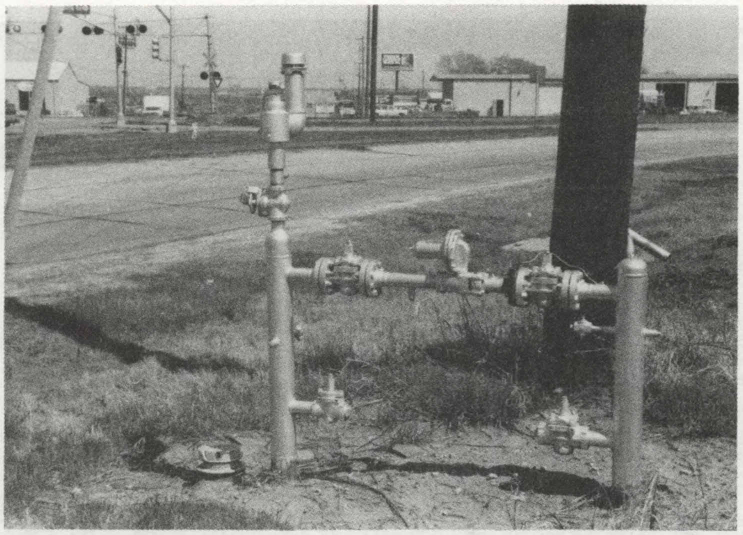
Example of a poorly protected and maintained city district regulator station.

Figure I-9



Stop valve (below relief valve in regulator station) must be locked in open position to assure relief valve will operate, if needed (49 CFR 192.199(h)).

Figure I-10



This illustrates a city regulator station which does not meet the pipeline safety standards. The station is also not protected against outside damage, such as damage from vehicles.

Q. CAST IRON PIPES

THIS WILL NORMALLY NOT APPLY TO MASTER METER OPERATORS OR LPG OPERATORS.

Operators with cast iron pipe must have certain provisions in their O&M plan. Each cast iron caulked bell and spigot joint that is subject to pressures of 25 psig or more must be sealed with either a mechanical leak clamp or material or device which:

- o does not reduce flexibility of the joint,
- o permanently bonds (either chemically or mechanically, or both) with the bell and spigot, metal surfaces or adjacent pipe metal surfaces, and
- o seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of 49 CFR 192.53(a)&(b) and 192.143.

Each cast iron caulked bell and spigot joint that is subject to pressure of less than 25 psig and is exposed for any reason, must be sealed by a means other than caulking (49 CFR 192.753.)

When an operator has knowledge that the support for a segment of a buried cast iron pipeline has been disturbed, that segment of the pipeline must be protected, as necessary. Examples of disturbances are:

- o Vibrations from heavy construction equipment, trains, trucks, buses, or blasting,
- o Impact forces by vehicles,
- o Earth movement,
- o Excavations near the pipeline,
- o Other known or foreseeable outside forces which may have or could subject that segment of the pipeline to bending stress.

R. ODORIZING YOUR GAS

THIS WILL NORMALLY NOT APPLY TO MASTER METER OPERATORS OR LPG OPERATORS.

Operators who must odorize their own gas must assure that there is enough odorant in the gas so that it is distinctive when natural gas is present in concentrations in air of one-fifth of the lower explosive limit. The lower explosive limit for natural gas is approximately 4 percent natural gas-in air by volume. Therefore, odorant must be present at approximately 1 percent gas in air by volume.

The odorant and its product of combustion cannot be toxic to humans, or harmful to components that make up piping system. The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

Operators must follow these basic rules (49 CFR 192.625):

- o Assure that all gas in distribution mains and service lines is odorized.
- o Specify or determine the type of odorant used in the system.
- o Specify in the O&M plan the manufacturer's recommended amount of odorant needed to be injected per MMCF of gas.

- o Include any maintenance procedures recommended by the manufacturer of the type of odorizer installed in system. Odorization equipment must introduce the odorant without wide variation in the level of odorant.

- o Sample periodically. The procedure must be part of your written O&M plan. Include periodic testing of your odorant injection rate, and testing at various locations, including the outer extremities of pipeline system. Verify that the odor is distinctive.

- o Maintain records of injection rate and odor sampling. For sample record see Appendix C, Form 10.

Appendix I contains more diagrams of odorization equipment, lists further guidelines on operating, maintenance, and design, and contains properties of LP-Gas.

CHAPTER II

MATERIALS QUALIFIED FOR USE IN GAS SYSTEMS

IN THIS CHAPTER. . .

The federal regulations contained in 49 CFR Part 192 list many different materials qualified for gas service. The materials and specifications listed in this manual are those which are most commonly used in gas distribution systems installed in the early 1980's. Not all qualified materials or specifications listed in Part 192 are included in this section.

It is important for an operator to know the material make-up and operating pressure of an existing system. Based on this knowledge, the operator should develop, or have a consultant develop, a list of qualified material for use for construction and repair of the gas piping system. Installation procedures should be included for each specific type of material used in the system. This can be accomplished by including or referencing manufacturer's "gas product installation manuals" in the O&M plan.

When purchasing material used in a gas system, it is extremely important to check the marking of the material. The marking on the material will help identify whether the material is qualified for gas service. When selecting a piping system, it is essential to know that the piping systems consist of pipe and fittings, not just pipe. Therefore, an operator must select materials that are compatible with each other. This chapter will cover the most common specifications and standards used by manufacturers for pipes, valves, flanges, regulators, and other equipment commonly used in gas distribution systems.

PIPE

Only steel and plastic pipe specifications are included in this manual. (For other qualified pipe see 49 CFR Part 192.) Below are listed pipe specifications. Be sure to check Appendix A of 49 CFR for current listings.

API 5L - Steel pipe
API 5LX - Steel pipe
ASTM A53 - Steel pipe

- ASTM A135 - Steel pipe
- ASTM A139 - Steel pipe
- ASTM A211 - Steel and iron pipe
- ASTM A381 - Steel pipe
- ASTM A539 - Steel tubing
- ASTM Specification A671 - Steel pipe
- ASTM D2513 - Thermoplastic pipe and tubing

The following table can be used for selecting the proper nominal wall thickness for steel pipe for use in a gas distribution system.

Nominal Pipe Size (inches)	Outside Diameter (inches)	Standard (Schedule 40) Wall Thickness (inches)	Minimum Wall Thickness After Threading (inches)
1/8	0.405	0.068	0.065
1/4	0.540	0.088	0.065
3/8	0.675	0.091	0.065
1/2	0.840	0.109	0.065
3/4	1.050	0.113	0.065
1	1.315	0.133	0.065
1 1/4	1.660	0.140	0.065
1 1/2	1.900	0.145	0.065
2	2.375	0.154	0.075
3	3.500	0.216	0.098
3 1/2	4.000	0.226	0.108
4	4.500	0.237	0.116
5	5.563	0.258	0.125
6	6.625	0.280	0.156
8	8.625	0.322	0.172
10	10.750	0.365	0.188
12	12.750	0.406	0.203

All the new steel pipe manufactured under the above specifications with the above wall thickness have design pressure up to at least 152 psig. Operators are cautioned that the actual maximum allowable operating pressure (MAOP) of a new or replacement pipe in a gas system is dependent upon the pressure test, performed on the pipeline system before it is put in service. It is also recommended that threaded pipe not be installed underground.

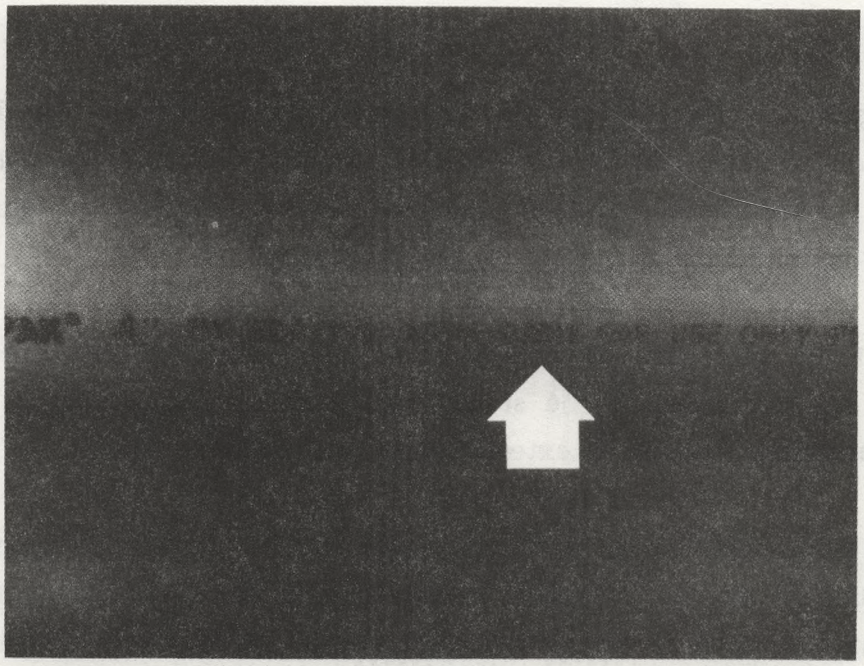
When purchasing polyethylene (PE) plastic pipe, it is required that the pipe be marked ASTM D2513. Plastic pipe with this marking is suitable for gas service. Fiberglass epoxy plastic pipe marked ASTM D2517 is also qualified for gas service. However, ASTM D2517 pipe is no longer installed by most gas companies.

At no time should the loading of the pipe cause the pipe section to lose its round shape. Plastic pipe and tubing should be stored and protected from damage. It could be damaged by crushing, piercing, or extended exposure to direct sunlight.

As a rule of thumb, never store plastic pipe outdoors for more than 6 months. It should be placed inside or covered to protect it from exposure to direct sunlight. It is a good idea to obtain the manufacturer's recommendation as to how long the pipe can be exposed to sunlight before it loses some of its physical strength.

In recent years the vast majority of natural gas companies have been installing ASTM D2513, polyethylene (PE) pipe. Some of the reasons PE pipe is being installed are: flexibility, good joining characteristics, durability, ease of installation, and cost. The PE designations most often used are PE 2306, PE 3306, PE 3406, and PE 3408. See Figure II-1.

FIGURE II-1



This is a picture of 4-inch SDR 11.5 PE pipe manufactured according to ASTM D2513. If you are going to use plastic pipe in your underground piping system, make sure it has ASTM D2513 stamped on it.

Most PE pipe manufacturers subscribe to the "Standard Dimension Ratio" (SDR) method of rating pressure piping. The SDR is the ratio of pipe diameter to wall thickness. An SDR 11 means the outside diameter (O.D.) of the pipe is eleven times the thickness of the wall.

For high SDR ratios the pipe wall is thin in comparison to the pipe O.D. For low SDR ratios the wall is thick in comparison to the pipe O.D. Given two pipes of the same O.D., the pipe with the thicker wall will be stronger than the one with the thinner wall. High SDRs have low pressure ratings; low SDRs have high pressure ratings because of the relative wall thickness. See the following table.

Design Pressure Rating for PE Pipe (2306,3306 and 3406) Plastic Pipe Listed by ASTM D2513

NOTE: THIS CHART DOES NOT APPLY TO PE 3408 PLASTIC PIPE

		Design Pressure Rating—PSIG At Various Temperatures			DIMENSIONS (Inches)			
					Outside Diam.		Wall Thickness	
Nominal Size	SDR†	Up to 100°F	120°F	140°F	Average	Tolerance	Minimum	Tolerance
Iron Pipe Size*								
½″	9.3	96	76	61	.840	±.004	.090	+.020 −.000
¾″	11	79	63	50	1.050	±.004	.095	+.021 −.000
1″	11	79	63	50	1.315	±.005	.119	+.026 −.000
1¼″	10	88	71	56	1.660	±.005	.166	+.026 .000
2″	11	80	64	51	2.375	±.006	.216	+.026 −.000
3″	11.5	76	61	49	3.500	±.008	.307	+.035 −.000
4″	11.5	76	61	49	4.500	±.009	.395	+.040 −.000
6″	21	40	32	25	6.625	±.011	.316	+.038 −.000
6″	11.5	76	61	49	6.625	±.011	.581	+.069 −.000
8″	21	40	32	25	8.625	±.013	.411	+.049 −.000
8″	11	80	64	51	8.625	±.013	.785	+.094 −.000
Copper Tubing Size*								
½″ (⅝″ OD)	7	100	100	86	625	±.004	.090	.006 −.000
1″ (1⅛″ OD)	11.5	77	61	49	1.125	±.005	.099	+.008 −.000
1″ (1⅛″ OD)	12.5	69	55	44	1.125	±.005	.090	+.008 −.000

† Standard Dimension Ratio is calculated by dividing the average OD of the pipe by the minimum wall thickness in inches, as described in ASTM D-2513, par. 3.3.

***Plastic pipe is purchased according to the iron pipe size (IPS) or the copper tubing size (CTS).**

This table is intended to be a guideline. The operator should check the manufacturer's specific pressure rating for each specific pipe.

Operators are cautioned that the actual MAOP of new or replacement pipe in a gas system is dependent upon: design pressure of the pipe and components in the system, and the pressure test performed by the operator or his contractor, on the piping system. This pressure test must be made before the system is put in service. (See Chapter III of this Guidance Manual.)

PE pipe may be joined by either the heat fusion method (butt or socket) or by a mechanical coupling. Both the joining procedures and the personnel making joints must be properly qualified. See Chapter III and Appendix K.

PE pipe that is not encased must have a minimum wall thickness of 0.090 inches. However, pipe with an outside diameter of 0.875 (3/4" nominal size) or less may have a minimum wall thickness of 0.062.

Acrylonitrie-butadiene-styrene (ABS), Cellulose acetate buytrate (CAB), Polybutylene (PB), and Poly vinyl choride (PVC) are also types of plastic pipe qualified for natural - NOT LP - gas service, if the pipe has the ASTM D2513 marking on it. However, most natural gas companies no longer install these types of plastic pipes in their gas system because they believe that PE pipe has superior characteristics.

For additional sources of information about plastic pipe see Chapter V of this guideline. You may also be able to obtain information about local suppliers of plastic gas pipe from the local gas utilities.

IMPORTANT NOTE TO LP-GAS SYSTEM OPERATORS:

The polyethylene plastic pipe, tubing, and fittings must be only those specific types designated as PE 2306, PE 3306, PE 3406, or PE 3408 and meeting the appropriate requirements of ASTM D2513.

Polyethylene is the only plastic that can be used in underground commercial LP-Gas distribution systems. These systems must operate at internal pressures and temperatures such that internal condensation will not occur.

For LP-Gas applications the maximum operating pressure is 30 psig. LP-Gas has a higher condensation temperature than does natural gas; this maximum pressure is recommended to ensure that plastic pipe is not subject to excessive exposure of LP-Gas liquids. PE pipes manufactured according to ASTM D2513 are the only plastic pipes qualified for use in petroleum gas systems.

VALVES

Each valve must meet the minimum requirements, or the equivalent, of API 6A, API 6D, MSS SP-70, MSS SP-71, or MSS SP-78. A valve may not be used under operating conditions that exceed the applicable pressure-temperature rating contained in those standards. The valve will be stamped with either the class (ANSI) or the maximum working pressure rating (PSIG). Never operate valves at pressures exceeding their rating. The class of ANSI ratings on steel valves are ratings which specify the maximum working pressure for flanged-end and weld-end gate, plug, ball, and check valves. See the following table:

Class Rating/Maximum Working Pressure

Class (ANSI)	150	300	400	600	900	1500	2500
Maximum Working Pressure Rating, PSIG	275	720	960	1440	2160	3600	6000

The maximum working ratings are applicable at temperatures from -20°F to 100°F.

Metal valves will often be stamped with the symbols "WOG." This means that they are suitable for service for water, oil or gas. Sometimes just the letter "G" (for gas) appears.

The manufacturer's name or trademark will also be included on a valve. Operators should maintain manufacturer's manuals which include installation, operation, and maintenance procedures for each different type valve in the gas system. These manuals and procedures should be incorporated or referenced into the O&M procedures.

A word about plastic valves. . . There are plastic valves which are suitable for gas service. Plastic valves purchased for gas service should comply with industry standard ANSI B16.40, "Manually Operated Thermoplastic Valves in Gas Distribution Systems." The valves must be compatible with the plastic pipe used in gas systems. It is important that operators find a supplier who is knowledgeable in the gas piping field before buying plastic valves. This supplier information can be obtained from trade journals, local gas associations (state or regional), or local gas utilities. See Chapter V.

FLANGES AND FLANGE ACCESSORIES

Each flange or flange accessory must meet the minimum requirements of ANSI B16.5, MSS SP-44, or ANSI B16.24.

Operators should verify that metal flanges purchased for their system meet the above requirements. This can be done by checking the markings on the flange. The markings are similar to those on the valves.

For plastic fittings made of PVC or ABS plastic, see 49 CFR 192.191

REGULATORS AND OVERPRESSURE PROTECTION EQUIPMENT

There are many different manufacturer models of gas regulators and overpressure equipment (relief valves) available for gas systems.

Regulators and overpressure protection equipment must be properly sized so that overpressure or low pressure conditions do not occur on the gas system. Manufacturers of gas regulators and relief valves have manuals which contain formulas and charts for each of their specific models or types of equipment. These charts and formulas are necessary to size regulators and relief valves properly. Operators who do not have a technical background may have to rely on a consultant or the equipment manufacturer representative to size the equipment. A qualified person must install the system. Check with your state for additional local requirements. Chapter V of this guideline also provides a listing of organizations and publications which may be helpful in selecting the proper equipment.

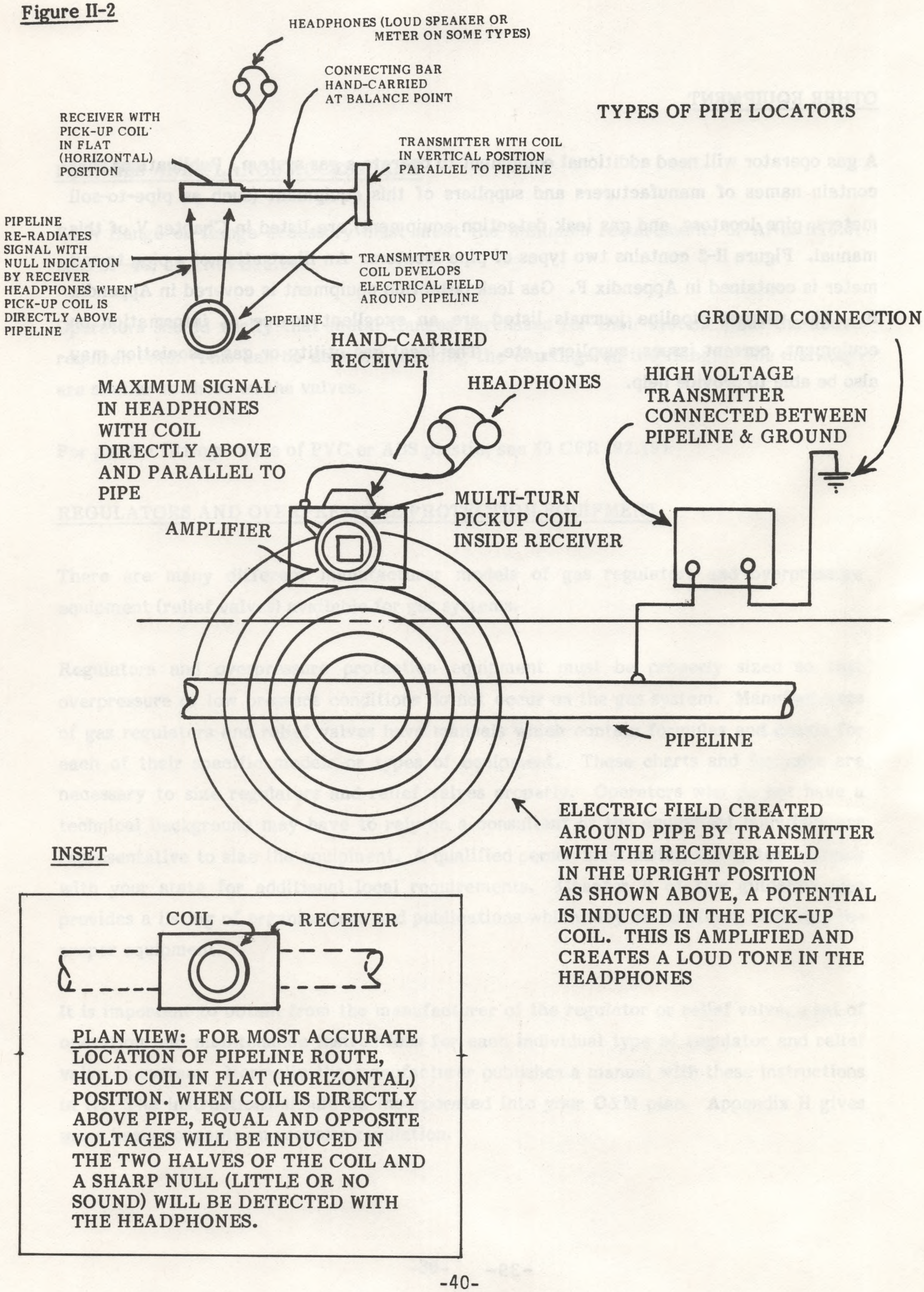
It is important to obtain from the manufacturer of the regulator or relief valve, a set of operation and maintenance instructions for each individual type of regulator and relief valve in system. Normally the manufacturer publishes a manual with these instructions in it. The instructions should be incorporated into your O&M plan. Appendix H gives more basic concepts on pressure regulation.

OTHER EQUIPMENT

A gas operator will need additional equipment to operate a gas system. Publications that contain names of manufacturers and suppliers of this equipment (such as pipe-to-soil meters, pipe locators, and gas leak detection equipment) are listed in Chapter V of this manual. Figure II-2 contains two types of pipe locators. An illustration of a pipe to soil meter is contained in Appendix F. Gas leak detection equipment is covered in Appendix B. The various pipeline journals listed are an excellent source of information on equipment, current issues, suppliers, etc. The local gas utility or gas association may also be able to provide help.

Figure II-2

TYPES OF PIPE LOCATORS



CHAPTER III

CONSTRUCTION AND REPAIR

IN THIS CHAPTER. . .

Repair, construction, and safety are based upon good common sense and sound engineering concepts. This chapter is designed to increase the safety of your gas system by helping you meet the construction and repair standards set by the pipeline safety code.

The manufacturers of pipe, valves, fittings, and other gas system components must design and test them to prescribed industry specifications. The specifications are incorporated into 49 CFR, Part 192. Those meeting the requirements are qualified for gas service and marked with the "approved" markings. (See Chapter II.) In addition, manufacturers usually develop procedures for joining their products and for joining other materials to their products. (Manufacturers will supply you with manuals of procedures for your O&M plan.)

This chapter outlines construction, pipe handling, and pressure testing requirements that should be followed when installing a gas system. It will explain steps and procedures necessary to qualify a person to make a gas joint. It gives directions for finding "qualified persons" to do the construction and repair work on your system. <u>If you are using a gas contractor to work on your system, it is your responsibility to see that the contractor follows all requirements.</u>

PLANNING AHEAD

Before making modification or repair of a piping system, you should make comprehensive plans. It is essential that a gas operator know the type of material and all the parts that make up the present gas piping system. The piping system consists of pipe, valves, fittings, regulators, relief devices, and meters. By knowing the type of materials in the system, an operator can select the proper fittings. Regulations require the inclusion of the proper leak repair procedure in the O&M plan. In addition, in order to develop a cathodic protection program, it is necessary to know the type of piping in the system.

Records of the type and location of material are critical for planning purposes. Operators who are uncertain of the type of material that make up their gas piping system should make an effort to identify the material. This may be done in one of the following manners:

- o Contact previous owners of the system.
- o Contact the contractor who put in the system.
- o Check city or county permits.
- o Carefully expose the pipe in certain locations to determine the type of pipe.

Operators unfamiliar with piping material will have to rely on a qualified person to identify the pipe.

EXCAVATION (DIGGING)

Before digging (for gas line installation, repair, or replacement) you must locate the pipe network and other underground utility lines on the property. Lines may be located by one or all of the following ways:

- o Locate all underground utility lines on "as built" or "corrected-for-construction" drawings. Maps or drawings of the location of the underground gas lines are very important. They can provide information to other utilities that must dig to repair or replace their utility lines.
- o Locate underground metallic utility lines with pipe locating instruments. Plastic pipe which was installed with an electrically conductive wire, as required in 49 CFR 192.321(e), can also be located by this method. Chapter II shows instruments typically used for location of underground pipes.
- o Locate or verify locations of other underground utility lines by communication with other utility companies (electric, water, sewer, telephone) serving the residential area.

In some areas of the country a single telephone call (e.g., one call system) can be made to notify the appropriate utilities of your intention to dig. If you are in such an area, be sure to call at least 48 hours in advance of digging.

A word on safety: service lines and mains, built prior to the enactment of minimum depth requirements, may be buried very shallow. Therefore, digging to expose gas lines for repair or replacement purposes should be carried out with hand tools (preferably made of brass or other non-sparking material) until the gas lines are located. Afterwards, power tools may be used.

When working on a leaking pipe, a stand-by worker should be ready to assist his partner in escaping from the hole in the event of an emergency. A fire extinguisher should be available.

PIPE INSTALLATION, REPAIR, AND REPLACEMENT: GENERAL COMMENTS

The pipeline safety standards allow gas service lines to be installed with as little as 12 inches of earth cover on private property and 18 inches of cover under streets and roads. Gas mains must have at least 24 inches of cover. MTB recommends that gas lines be installed at greater depths, especially where soil erosion is prevalent. If your state or local codes require greater depths, use the state or local code for underground pipe installation purposes.

Underground structures may prevent the installation of gas services or main lines at these minimum depths. The pipeline safety requirements allow a shallower depth of cover if adequate protection (i.e., sufficient to withstand the anticipated external loads) is provided (e.g., heavier pipe, casing, concrete, etc.) In such cases, it is recommended that the gas line location be marked above ground. The area should be inspected frequently to insure that the ground cover has not eroded.

Installation of gas pipes must be conducted by qualified personnel. The local gas utility company may be able to recommend reputable qualified persons/contractors who have the necessary background for gas pipe installation. Your local associations, such as the State LP-Gas Association or mobile home associations, may have this information. However, contractor work must be supervised carefully. The following sections list required joining and construction practices that must be followed.

METALLIC PIPE INSTALLATION

All the conditions listed below must be met when you install metallic pipe.

- o Make each joint in accordance with written procedures that have been proven by test or experience to produce strong gas tight joints.

- o Obtain and follow the manufacturer's recommendations for each specific fitting used. See Figure III-1 for an example of a manufacturer's instructions for a mechanical coupling. Keep the manufacturer's procedures for your O&M plan.

- o Handle pipe properly without damaging the outside coating. Any gouges or scratches should be covered with an appropriate coating. If coating damage is not corrected, accelerated corrosion can occur in that area.

- o Coat or wrap steel pipe at all welded and mechanical joints before backfilling.

- o Pressure test new pipe for leaks before backfilling. Mains to be operated at less than 1 psig should be tested to at least 10 psig. Mains to be operated at or above 1 psig must be tested to at least 90 psig. Service lines to be operated at 1 psig but not more than 40 psig must be given a leak test at a pressure of not less than 50 psig. Additional details on pressure testing are contained in Appendix L.

- o Support the pipe along its length with proper backfill.

- o Make certain that backfill material does not contain stones, cinders, bottles, or cans that may damage or scratch pipe coating.

- o Cathodically protect steel pipes.

- o Electrically insulate dissimilar metals. (See Appendix F for illustrations.)

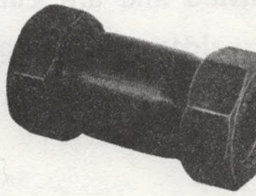
- o Make certain that compression type fittings that are intended to be electrically conductive have armored gaskets. Bond over insulating fittings to maintain electrical continuity for cathodic protection and for locating steel pipe.

Figure III-1

DRESSER

GAS PRODUCT INSTALLATION MANUAL

Style 90 Couplings and Fittings for Steel Pipe



1. Clean pipe surface to bare metal for a distance of four inches from the pipe ends (for 10" long bodies—seven inches).
2. Loosen nuts about one-quarter turn and make sure gasket is loose.
3. Apply soap-water to gaskets (ethylene glycol should be added in freezing weather).
4. Stab pipe ends into coupling or fitting. Center coupling over joint.
5. Tighten each nut independently while holding coupling or fitting body from turning. See table for wrench size. In each case, a pull of about 75 pounds should be applied to the end of the wrench.

Recommended Wrench Sizes for use with Dresser Compression Couplings and Fittings

Nominal Steel Pipe Size (I.D.)	Recommended Wrench Size
¼"	10"
⅜"	10"
½"	14"
¾"	14"
1"	18"
1¼"	18"
1½"	24"
2"	24"

6. Line caps must be securely anchored to prevent blow-off under pressure.

When pipe movement out of the coupling or fitting might occur, proper anchorage of the pipe must be provided.

Note: Use armored gaskets or bond coupling for cathodic protection and pipe locating continuity.

If you must weld steel in pipeline, you should review the pipeline safety requirements covered in Subpart E of 49 CFR Part 192. With the current material available for gas service (repair fittings, clamps, sleeves, tees, etc.) there should be little need to do much welding on a small gas distribution system for operation and maintenance purposes. The important things to remember are that welding must be performed in accordance with established written welding procedures that have been qualified and are current to produce sound ductile welds, and welding must be performed by welders who are qualified for the welding procedure to be used. Some states have special welding certification programs.

Welding of steel pipe is difficult. Both the procedures and the personnel must be qualified for the type of weld performed. If welding must be done on system, you may be referred to qualified welders by:

- o The local gas utility,
- o Your local associations (such as mobile home associations, LPG associations, municipal associations), or
- o Your consultant.

Review Appendix J if you plan to weld. It contains the federal welding requirements.

PLASTIC PIPE INSTALLATION

Plastic pipe is now commonly used for distribution mains and services by the gas industry. The most common type of plastic pipe presently installed is polyethylene (PE.) PE plastic pipe is the only acceptable plastic for LP gas piping and is recommended as the most suitable plastic pipe for natural gas piping. PE plastic pipe is manufactured according to ASTM D2513 and is marked with that number.

Plastic pipe may be buried directly in the ground. Also, it may be used to replace a deteriorated buried metal pipe. A slightly smaller plastic pipe is inserted into the existing metal pipe. (See Appendix L.)

An operator may do his own installing of plastic pipe in the gas system. If so, the operator must include written joining procedures in the O&M plan. Each joint must be made in accordance with written procedures that have been proven by test or experience

according to the requirements contained in 49 CFR 192.283. (See Appendix K.) The personnel who make the joints must meet the requirements contained in 49 CFR 192.285.

Operators need not run the tests described in 49 CFR 192.283 themselves because most pipe and fitting manufacturers develop and qualify joining procedures for each specific product. The vast majority of small gas system operators will not have the equipment or the expertise to run these tests themselves. Do not purchase the product if you can not certify that the manufacturer or supplier of the pipe or fitting has the joining procedures which meet the requirements of 49 CFR 192.283.

Manufacturers of both pipe and fittings have installation manuals which describe the specific joining procedure required to make a strong gas tight joint. The manufacturer's procedures for each of the pipeline components that are used in the system should be incorporated into the O&M plan. Operators are cautioned that if you join (fuse) PE pipe manufactured by different manufacturers, you may have to develop and qualify your own joining procedures.

If a contractor installs P.E. plastic pipe, the operator is responsible to see that only PE pipe manufactured according to ASTM D2513 is installed. In addition, the operator must verify that the contractor follows written joining procedures which meet the manufacturer's recommended joining procedures for the specific pipe and fitting used.

According to the safety standards (49 CFR 192.285) a person making joints must be qualified. The regulations state:

§ 192.285 Plastic pipe; qualifying persons to make joints.

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by—

(1) Appropriate training or experience in the use of the procedure; and

(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be—

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(2) In the case of a heat fusion, solvent cement, or adhesive joint:

(i) Tested under any one of the test methods listed under § 192.283(a) applicable to the type of joint and material being tested;

(ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

(iii) Cut into at least 3 longitudinal straps, each of which is—

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(c) A person must be requalified under an applicable procedure, if during any 12-month period that person—

(1) Does not make any joints under that procedure; or

(2) Has 3 joints or 3 percent of the joints made, whichever, is greater, under that procedure that are found unacceptable by testing under § 192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in his system is qualified in accordance with this section.

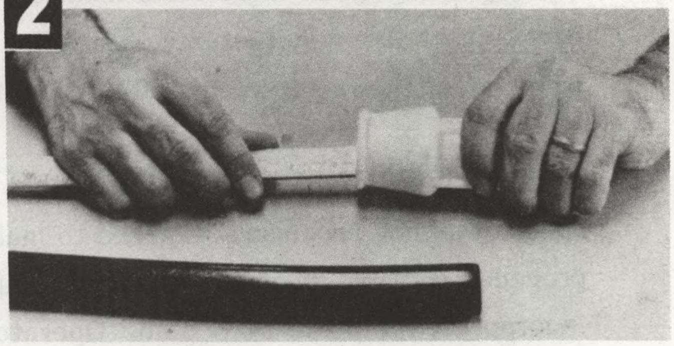
FIGURE III-2 is an example of a manufacturer's procedure for installing a specific coupling. If operator follows instructions and joint has same appearance as picture, then operator has met this requirement.

Self-Lock Plastic Pipe Couplings utilize a very simple and basic design concept. The split grip ring expands to allow the pipe to enter the coupling. Simultaneously, the ring wedges against the tapered sidewall. The pipe is gripped by the teeth on the ring, and will not pull out of the coupling. The stronger the tensile force on the pipe, the greater the gripping action of the ring. The seal is a simple "O" ring which seals on the OD of the pipe and the ID of the coupling. All units are 100% shell tested to assure structural integrity.

1 PIPE PREPARATION

First cut polyethylene pipe as square as possible. Then, using proper KCT Chamfering Tool, lightly rotate tool several times in a clockwise direction. After several light turns, a perfect 45 degree bevel will be formed on the pipe. Inspect end of the pipe to insure there are no deep scratches. Deep gouges can ultimately result in leakage at the "O" ring seal.

2 MEASURE ENGAGEMENT LENGTH

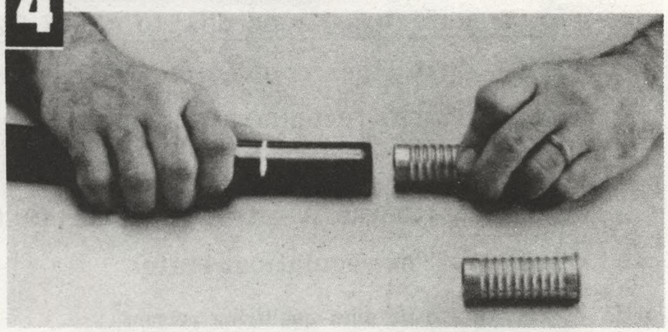


Measure engagement length or inside stab length of Self-Lock Coupling. This engagement length is given in the table, page 3, of Self-Lock Coupling Catalog SLC. Engagement length is also indicated on KCT Chamfering Tool.

3 MARK PIPE WITH ENGAGEMENT LENGTH

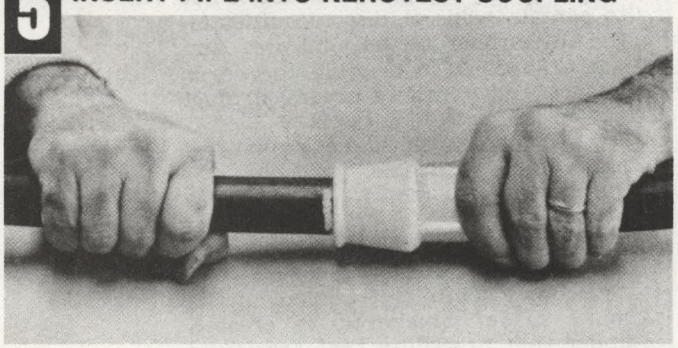
Using engagement length obtained in Step #2, mark engagement or stab length on pipe.

4 INSERT STIFFENER



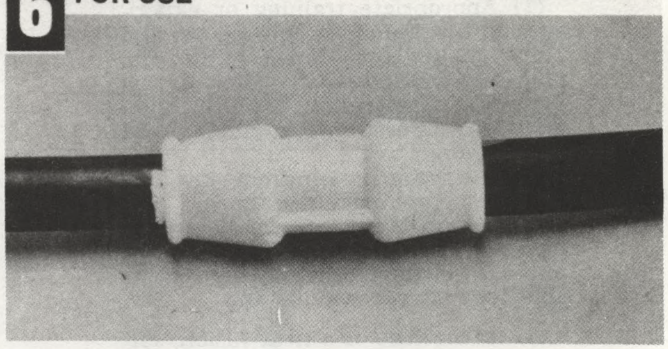
Insert stiffener into end of pipe. Stiffeners are mandatory—leakage under bending loads can occur if stiffeners are omitted.

5 INSERT PIPE INTO KEROTEST COUPLING



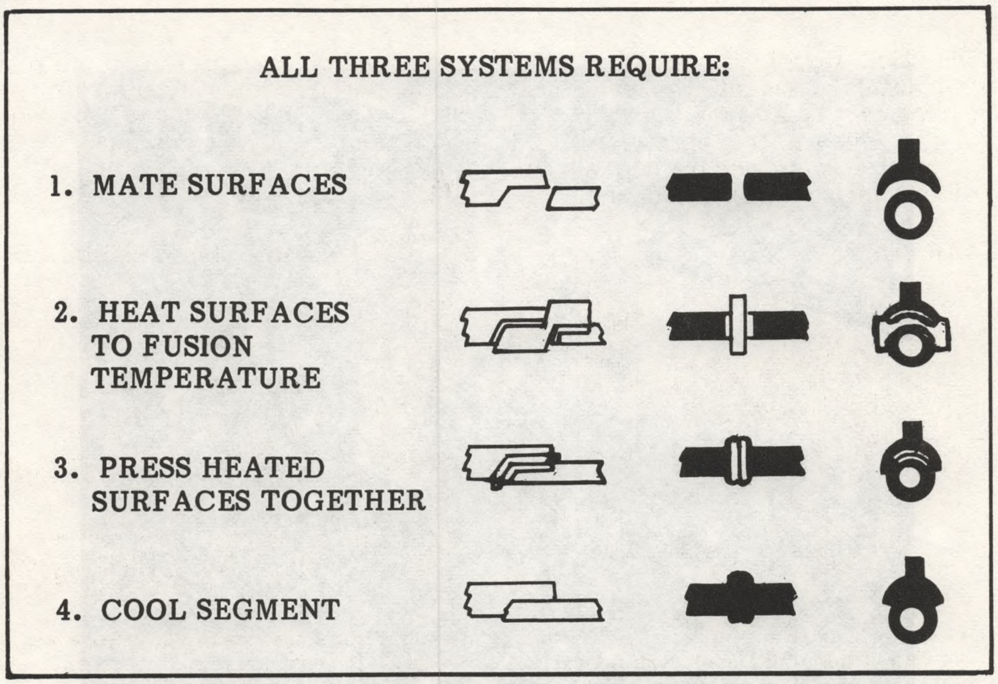
Lubricate the end of the pipe with a mild soap solution or water. This reduces the amount of force required to push the pipe into the coupling. Firmly grip Self-Lock Coupling. Using a rotary motion, insert plastic pipe into Self-Lock Coupling until it butts against the stop. Check for full engagement.

6 INSTALLATION BUBBLE TIGHT AND READY FOR USE



You have now completed a field joint in a matter of minutes. This joint is stronger than the polyethylene pipe and is gas tight. This coupling is ideal for field repair or new installations, eliminating the need to bring fusion equipment into the field.

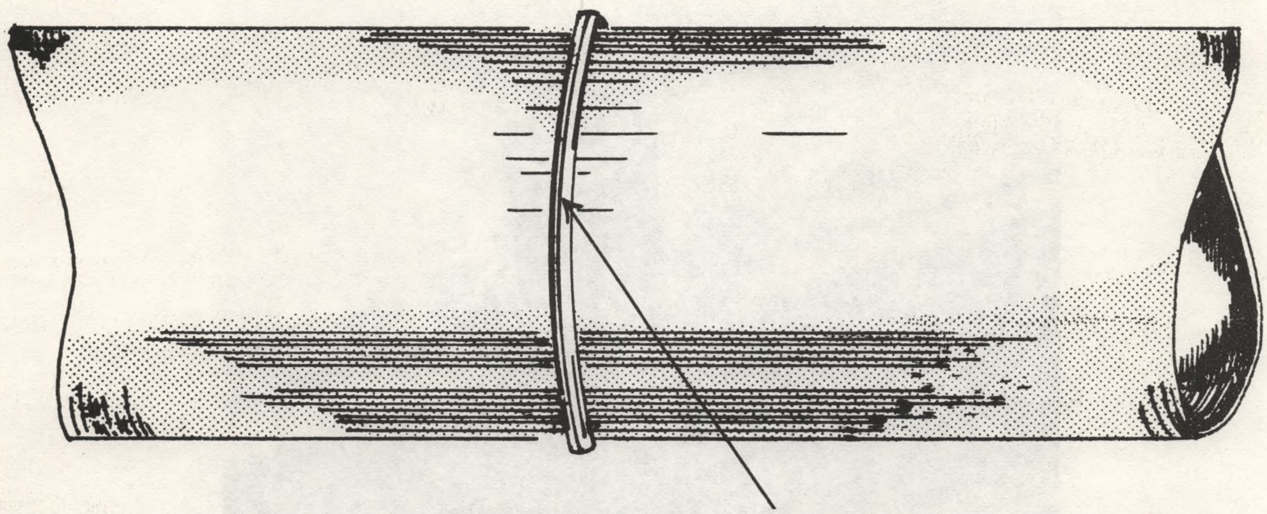
Figure III-3



These are the three types of fusion joints.

Figure III-4

Bead (melted and fused portion of plastic pipe)



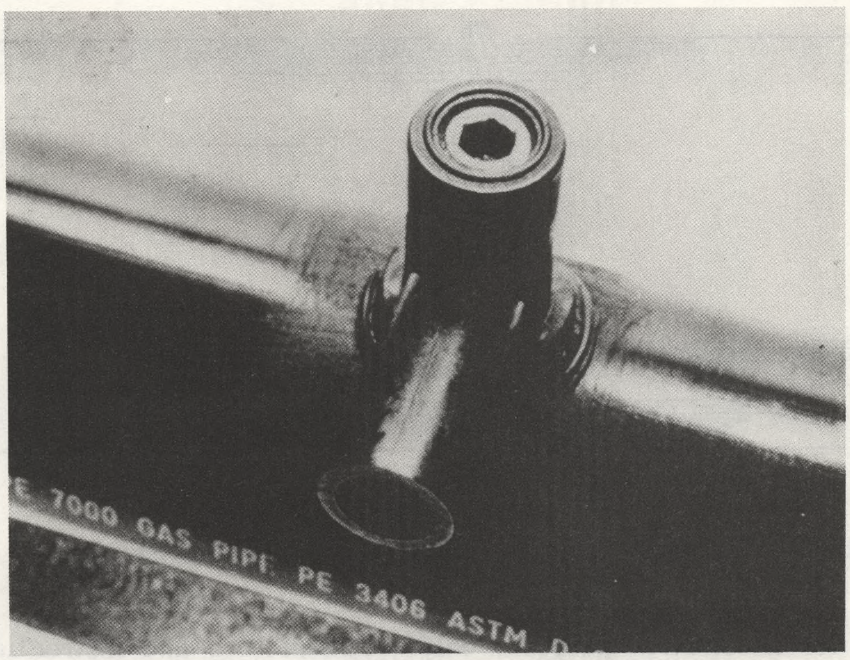
Close up of a well made butt fused joints made with ASTM D2513 PE pipe.

NOTE: This is for illustration purposes only. Use picture and instructions in pipe manufacturer's manual.

Figure III-5

This is an example of a socket fused joint with orange PE pipe listed in ASTM D2513.

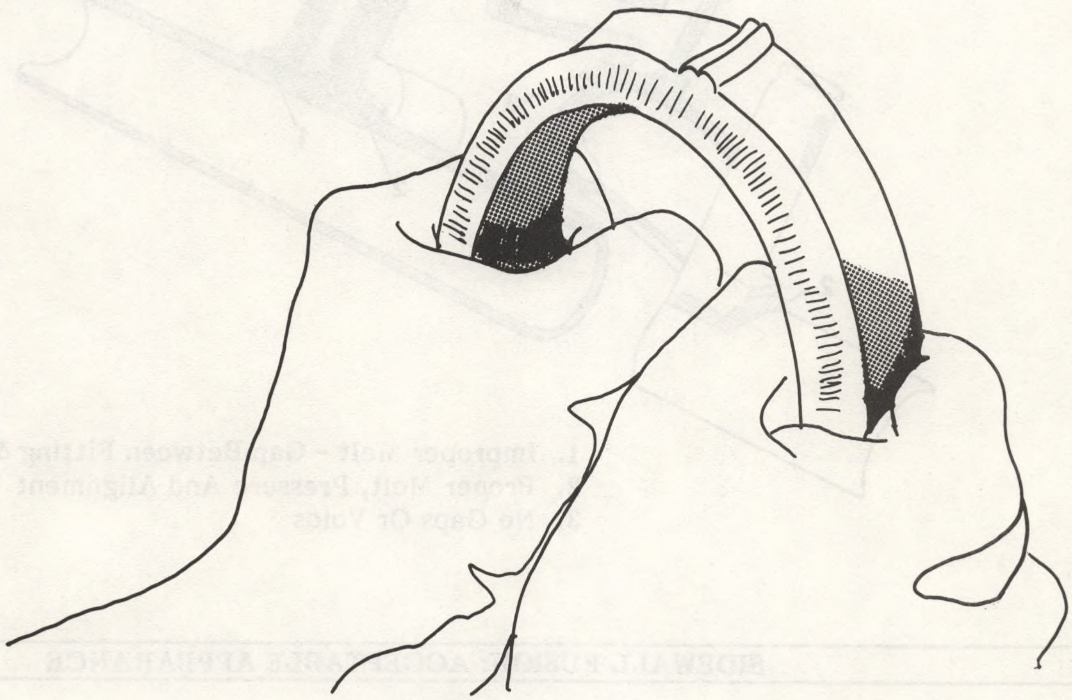
Figure III-6



This is an example of a saddle service tee joint made with PE pipe listed in ASTM D2513

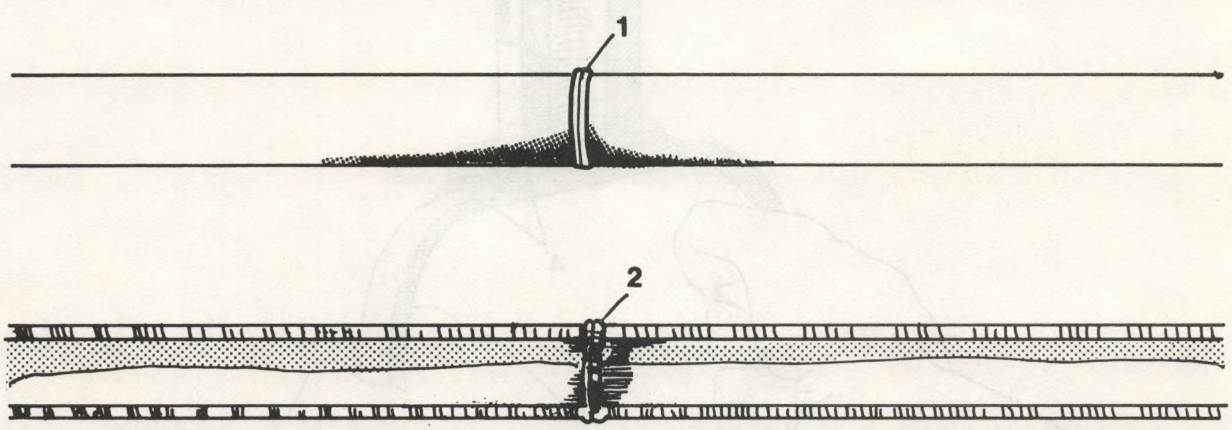
Figure III-7

BUTT FUSION OF PIPE: ACCEPTABLE APPEARANCE



Proper Alignment - No Gaps Or Voids

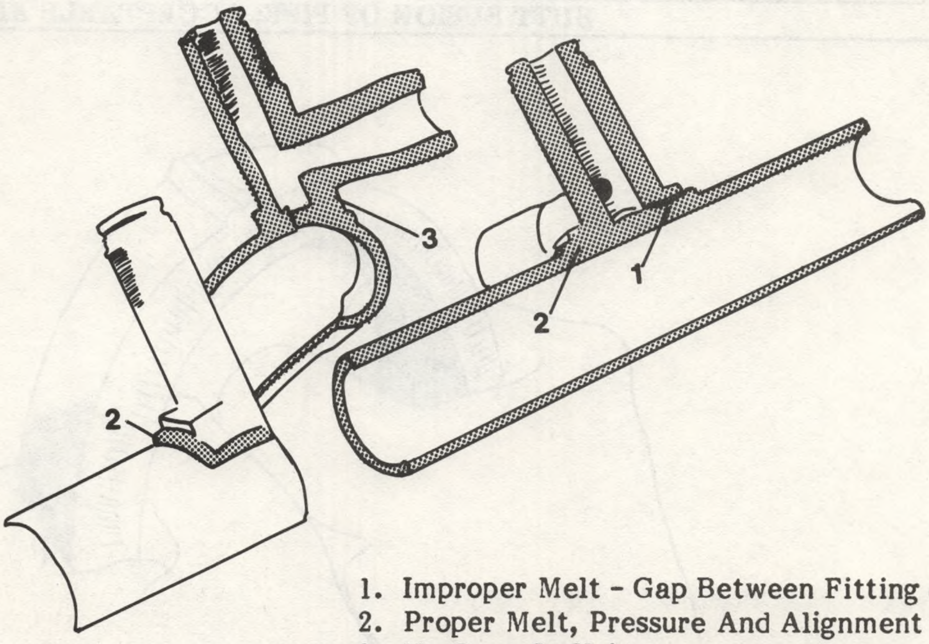
BUTT FUSION OF TUBING: ACCEPTABLE APPEARANCE



1. Proper Double Roll Back Bead
2. Proper Melt, Pressure And Alignment

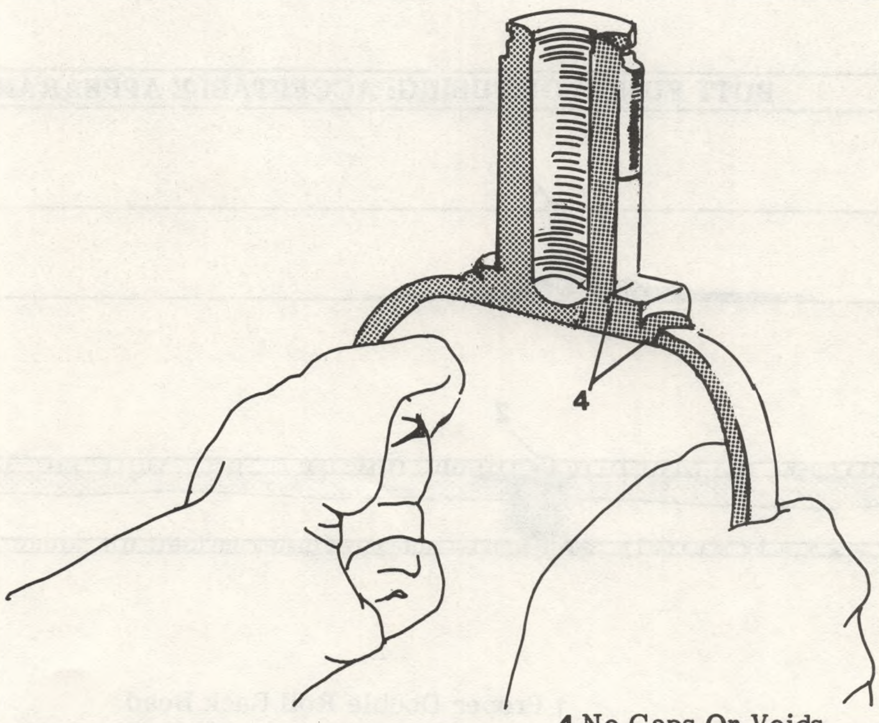
SIDEWALL FUSION: ACCEPTABLE APPEARANCE

Figure III-8



1. Improper Melt - Gap Between Fitting & Pipe
2. Proper Melt, Pressure And Alignment
3. No Gaps Or Voids

SIDEWALL FUSION: ACCEPTABLE APPEARANCE



4. No Gaps Or Voids

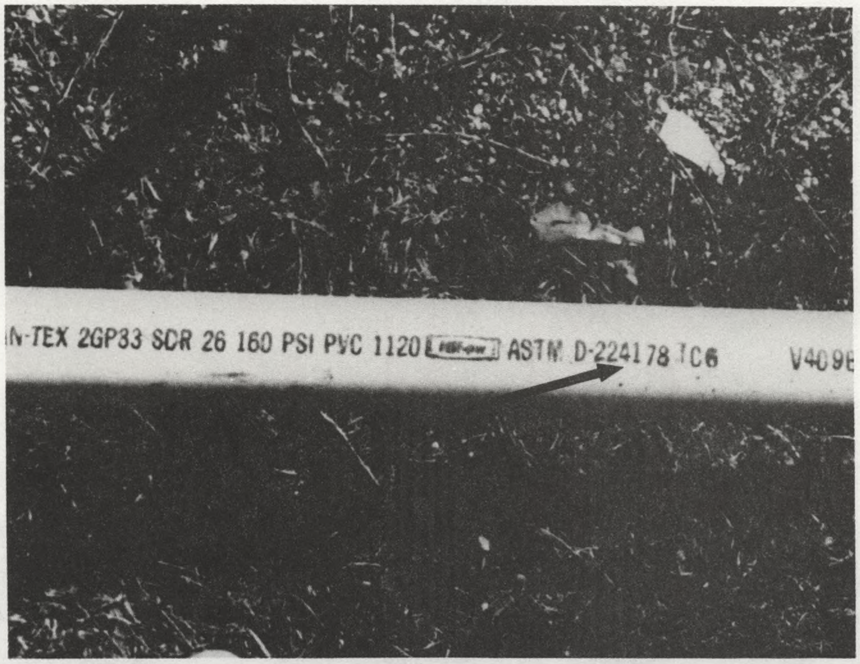
The general rules to follow when installing plastic pipe are listed below:

Rule 1: Install plastic pipe manufactured under the ASTM D2513 specification. The pipe must have ASTM D2513 marked on it. (See Figures III-9 and III-10)

Figure III-9

This is a properly marked PE pipe. ASTM D2513 is clearly marked on the pipe. If ASTM D2513 is not marked on a pipe, do not purchase it. The "SDR 11.5" gives the manufacturer's design pressure. See Chapter II regarding design pressure specifications.

Figure III-10



This is an example of pipe not qualified for gas piping. This is PVC pipe. It was manufactured according to ASTM D2241. The pipe is qualified for use as water pipe, but not gas piping. Remember to look for the ASTM D2513 marking on the pipe.

Rule 2: Make each joint in accordance with written procedures that have been proven by test or experience to produce strong gas tight joints.

The manufacturer of the pipe or fitting should supply the operator with the procedures for his specific product in the manufacturer's manual. When installing the pipe, make certain that these procedures are followed. (49 CFR 192.283) All joints must be made by a person qualified under 49 CFR 192.285.

Rule 3: Valves for use in plastic pipe must be designed and installed in a manner which will protect the plastic material. Protect the pipe from excessive torsional (twisting) or shearing (cutting) loads when the valve is operated. Protect from any secondary stresses which might be induced through the valve or its enclosure.

Rule 4: Prevent pullout and joint separation. Plastic pipe must be installed in such a manner that expansion and contraction of the pipe will not cause pullout or separation of the joint. Operators unfamiliar with plastic pipe should have a qualified person perform all these procedures.

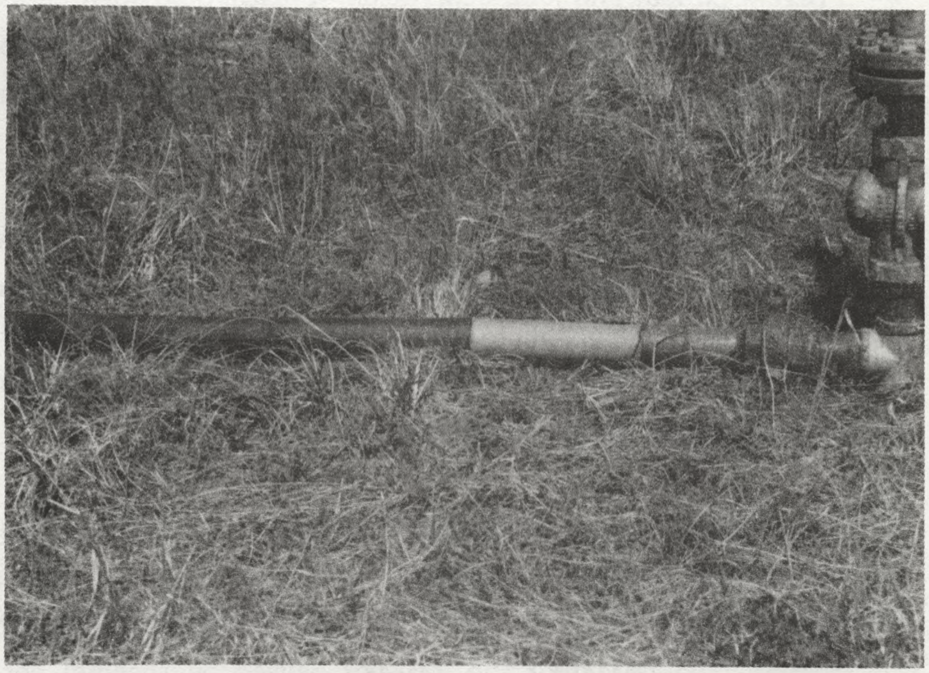
Rule 5: When inserting plastic pipe in a metal pipe, a sufficient allowance for thermal expansion and contraction must be made. Make an allowance at lateral and end connections on inserted plastic pipes, particularly those over 50 feet in length. End connections must be designed to prevent pullout caused by thermal contraction.

It is desirable that fittings used should be able to restrain a force equal to or greater than the strength of the pipe. If not, the pipe should be restrained by anchoring, bracing, offset connection, or straps across the fitting. To minimize the stresses caused by thermal contraction, pipes inserted in summer should be allowed to cool to ground temperature before tie-ins are made. Inserted pipes, especially those pulled in, should be relaxed, mechanically compressed, or cooled to avoid initial tensile stress. Operators unfamiliar with proper anchoring, offset connection, or strapping across a fitting, need to have a qualified person develop the proper procedures.

Rule 6: Repair or replace imperfections or damages before placing the pipe in service.

Rule 7: In the installation of plastic main all pipe must be below ground level (buried.) Where the pipe is installed in a vault or other below-grade enclosure, it must be completely encased in gas-tight metal pipe with fittings that are protected from corrosion. (For service line, see Rule 8.) The plastic pipe installation must minimize shear and other stresses. Thermo-plastic (PE) pipe for direct burial must have a minimum wall thickness of 0.090 inch. [Exception: pipe with an outside diameter of 0.875 inch (7/8") or less may have a minimum wall thickness of O.062 inch.] A plastic main that is not encased must have an electrically conductive wire or other means of locating the pipe while it is underground.

Figure III-11

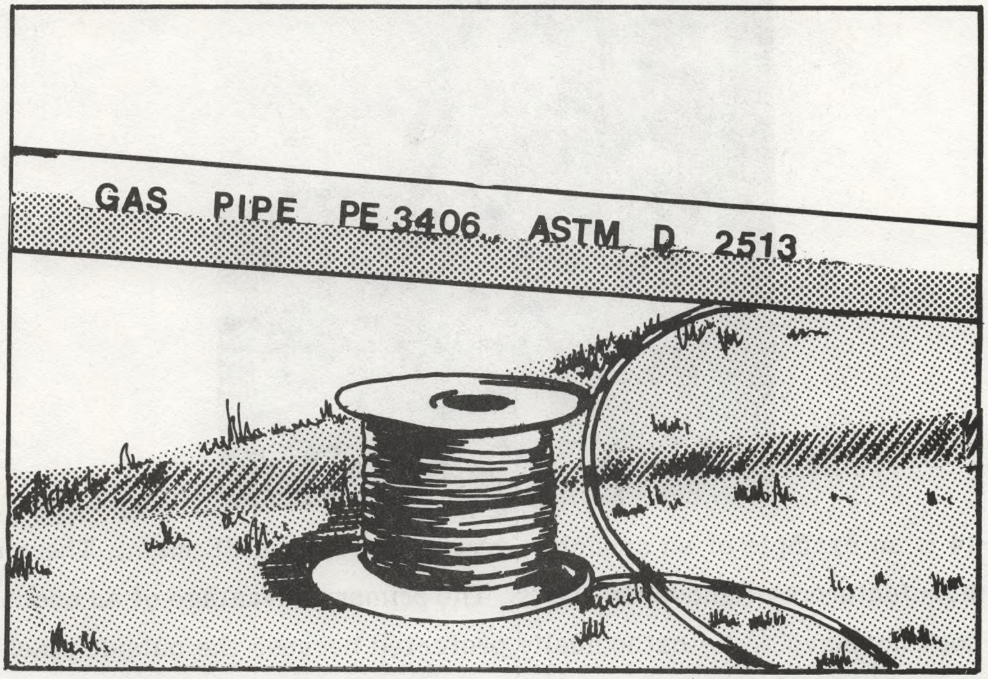


This is an example of an illegal installation which does not meet federal safety standards. This is a picture of PVC plastic pipe installed above ground. Remember to bury plastic pipe.

Figure III-12

This is an example of another improper installation. Note that a trench was dug but the operator never buried the pipe. Remember that plastic pipe looses some of its strength when exposed to sunlight for a long period of time.

Figure III-13



This is an example of some metallic wire used to help locate buried plastic pipe. Pipe locators can detect metal but not plastic. Therefore, metallic wire is often buried along the plastic pipe. A pipe locator can then detect the buried metallic wire and the adjacent plastic pipe.

Rule 8: All plastic service lines must be installed below ground. A portion of the plastic service line may terminate above ground if it is protected against deterioration and external damage by a casing. The plastic must not be used to support external loads.

Figure III-14

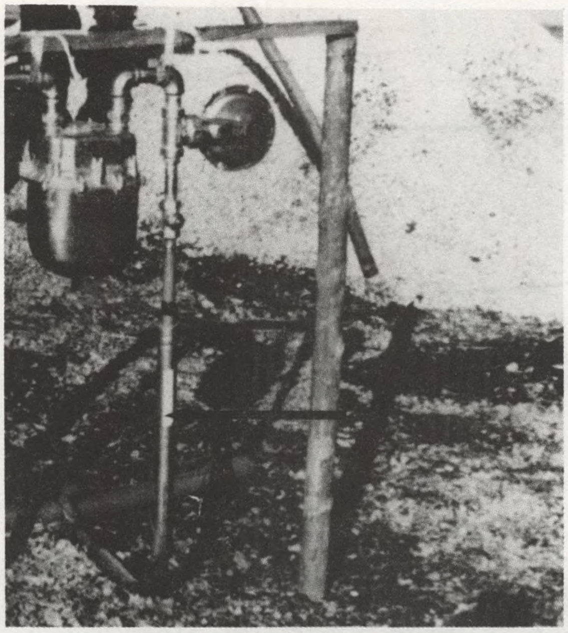


Figure III-14 is an example of an anodeless service riser off a PE main. There are many different manufacturers of anodeless risers. The primary advantage of an anodeless riser is that it does not have to be cathodically protected because the outside steel casing is not the gas carrier. The plastic inside the steel casing is the gas carrier. If you purchase anodeless risers, make sure that they meet all DOT requirements. If you install steel risers connected to plastic pipe by a transition fitting, make sure that you coat the steel riser and cathodically protect it.

Rule 9: The test pressure for an installed plastic pipe must be at least 150 percent of the maximum operating pressure or 50 psig, whichever is greater. However, the test pressure may not be more than three times the design pressure of the pipe. (For additional details see Appendix L.)

Rule 10: Special care must be taken to ensure that plastic pipe is continually supported along its entire length by properly tamped and compacted soil.

Rule 11: If plastic pipe is laid where there has been digging and backfilling below the pipe, the pipe must be reinforced. To prevent any shear or other stress concentrations, use external stiffeners at connections to main, valves, meter risers, and other places where compression fittings might be used. (See Appendix L.)

Rule 12: In the laying of plastic pipe, there should be adequate slack (snaking) in the pipe to prevent pullout due to thermal contraction.

Rule 13: Plastic pipe must be laid and backfilled with fill material that does not contain any large or sharp rocks, broken glass, or other objects which could cut or puncture the pipe. Where such conditions exist, suitable bedding (sand) and backfill must be provided.

Rule 14: Special care should be taken to prevent coal tar type coatings or petroleum base tape from contacting the plastic pipe. It can cause plastic pipe to deteriorate.

Rule 15: Static electricity can ignite a flammable gas-air atmosphere. When working with plastic pipe of any kind where there is (or there may be) the possibility of a flammable gas-air atmosphere, take the following precautions:

- o Use a grounded wet tape conductor wound around, or laid in contact with, the entire section of the exposed piping.

- o If gas is already present, wet the pipe starting from the ground end with a very dilute water and detergent solution. Apply tape immediately and leave it in place.

- o Wet the tape occasionally with water. Where temperatures are below freezing ($0^\circ C/32^\circ F$) add glycol to the water to maintain tape flexibility. Ground the tape with a metal pin driven into the ground.

- o <u>Do not vent gas using an ungrounded plastic pipe or tubing.</u> Even with grounded metal piping, venting gas with high scale or dust content could generate an electric charge in the gas itself and an arc could result from the dusty gas cloud back to the pipe and ignite the gas. Only vent gas at a downwind location remote from people or flammable material.

o NOTE: dissipating the static charge buildup with wet rags or a bare copper wire or other similar techniques may not be as effective as the above procedure. In all cases, use appropriate safety equipment such as flame resistant and static free clothing, breathing apparatus, etc.

REPAIR METHODS - PLASTIC AND METAL

Replacement of gas lines and repair of leaks are highly specialized and potentially hazardous operations. They should only be attempted by persons with adequate training and certification. Only maintenance personnel with such training, experience and certification should attempt repair of gas leaks or replacements of gas lines. If such personnel are not available, arrangements should be made with a qualified gas contractor, or the local gas company, to perform the work.

Leaks in service lines or mains may be repaired by cutting out a short length of pipe containing the leak. Replace it with a new segment of pipe. The pipe segment is attached to the existing line with couplings at each end. Compression couplings are commonly used for this purpose. See Figure III-1. Remember that written procedures are required to be followed for each joint made. The proper procedures can be obtained from the manufacturer of the coupling. If the operator intends to make the repair with a compression coupling, then the written procedures must be incorporated into the O&M plan.

Small leaks in steel service lines or mains, such as those resulting from corrosion pitting, may be repaired with a steel band clamp applied directly over the leak. All bare metal pipe and fittings installed below ground must then be properly coated and cathodically protected before backfilling.

If several leaks are found and extensive corrosion has taken place, the most effective solution may be to replace the entire length of pipe that has deteriorated. For these more extensive types of repair, the normal installation practices must be followed. They include priming and wrapping of all bare metallic piping and fittings, proper grading of lines to the main, cathodic protection, etc.

Leaking metal pipe can often be replaced by inserting PE pipe manufactured according to ASTM D2513 in the old line and making the appropriate connections at both ends. Again, operators are cautioned that allowance for thermal expansion and contraction must be made at lateral and end connections. Operators unfamiliar with proper anchoring and offset connections should have a gas-fitting contractor, or qualified person perform this work. Some of the PE pipe manufacturers include in their manuals details for the proper techniques to install their product by insertion.

One source of failures in plastic pipe is mechanical breaks associated with compression fittings at the transition of plastic pipe to metal pipe. Such failures are caused by a combination of factors. The primary source of the problem is inadequate support of the plastic pipe. The safety requirements in 49 CFR 192.319, 192,321, and 192,361, prescribe firm compaction (packing) of soil under the pipe to produce proper support. In practice, however, it is laborious, time consuming and difficult to achieve adequate compaction under such joints. Further, as the soil settles, stress may build and the insert sleeve will cut through the pipe. For example, an insert sleeve must be used in the plastic pipe to provide proper resistance to the clamping pressure of compression fittings. This internal tubular sleeve must extend beyond the end of the compression fitting. (See Appendix L.) If the pipe is not properly supported at that point, the end of the insert sleeve will act as a shear.

However, this source of failure in plastic pipe can be reduced or eliminated. Use a properly designed outer sleeve to prevent stress concentrations at the point where the plastic pipe leaves the compression fitting, main, or other related connection. To the maximum practical extent, compact the soil beneath the joint. (See Appendix L.)

Again, most fitting manufacturers have detailed installation instructions. Operators should obtain these instructions from the manufacturer or his representative. Incorporate these instructions into your O&M plan. (See Figures III-1 and III-2)

The most prevalent cause of breaks or leaks in plastic pipe is "third-party" damage. This is usually caused by a contractor breaking or cutting the pipe while digging. Plastic pipe is more vulnerable to such breaks than steel pipe. The lower strength of plastic pipe, however, is not necessarily a disadvantage. For example, if digging equipment hooks and pulls a steel pipe it may not break. However, the steel pipe may be pulled loose from a connection at some distance from the digging. The resulting leaks could go undetected

for a period of time and may result in a serious incident. Although there is no assurance that the plastic pipe will not also pull out, it is more likely to break at the point of digging. Then, the break can be easily detected and repaired.

After a leak has been repaired with a coupling or a clamp, a soap-bubble test must be conducted. (See Appendix B, "Warning Signs of a Leak," #7) Replaced main and services must be pressure tested for leaks.

Again, it should be emphasized that all sources of ignition should be kept away from the leak repair area. <u>MATCHES SHOULD NEVER BE USED TO DETECT A GAS LEAK</u> or to test the adequacy of a repair job.

CHAPTER IV
PROPER LOCATIONS AND DESIGN OF CUSTOMER METER AND REGULATOR SETS

IN THIS CHAPTER. .

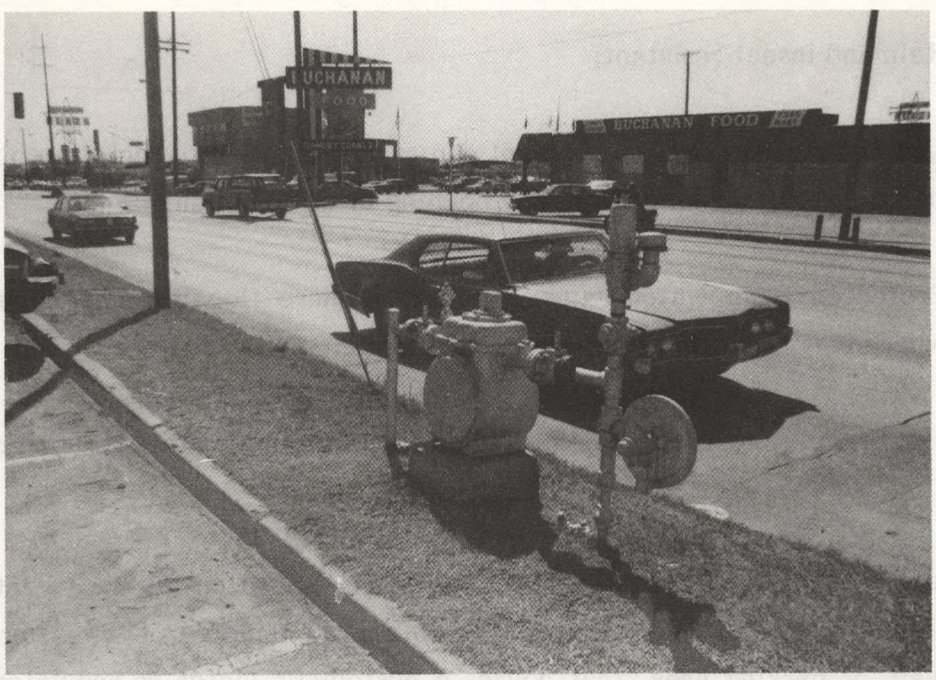
Before you locate your customer meters and regulators, you must consider three points: accessibility, protection of meter sets from damage, and protection of people from release of gas at the meter set.

This chapter gives the regulations covering location of meters and regulators. Guidelines are given for compliance with 49 CFR Part 192.

CUSTOMER METERS AND REGULATORS: LOCATION (49 CFR (192.353))

Install meters and service regulators in a readily accessible location. Protect the meters and regulators from corrosion and other damage. Install meters outside wherever possible. See Figure IV-1.

Figure IV-1



This meter may be readily accessible but it is certainly not protected from outside damage.

If you install a service regulator in a building, put it as close as practical to the point of service entering the building. You must vent the regulator to the outside.

If you install a meter in a building, you must locate it in a ventilated place. It must be more than 3 feet from any source of ignition or any source of heat which might damage the meter.

It is best to locate the upstream regulator (in a series) outside the building. However, you may locate regulators in a separate metering or regulating building.

CUSTOMER METERS AND REGULATORS: PROTECTION FROM DAMAGE (49 CFR 192.355)

Protection from vacuum or back pressure. If any of your customer's equipment might create either a vacuum or a back pressure, then you must install a device to protect the gas system.

Service regulator vents and relief vents. The outside terminal of each service regulator vent and relief vent must be:

- Rain and insect resistant;
- Located where gas from the vent can escape freely into the atmosphere. Vent it 3 feet or more away from any opening into the building; and
- Protected from water damage in areas where flooding may occur. Put it where it will not be under water in a flood.

The meters and regulators must be installed so as to minimize stresses upon connecting piping.

Each regulator that is designed to release gas in its operation must be vented to the outside atmosphere at least 3 feet from an opening into a building. Each pit or vault in a road, driveway, or parking area, that houses a customer's meter or regulator, must be able to support the vehicle traffic that could use that road, driveway, or parking area.

CUSTOMER METER INSTALLATIONS: OPERATING PRESSURE (49 CFR 192.359)

A meter may not be used at a pressure that is more than 67 percent of the manufacturer's shell test pressure (0.67 x shell test pressure.)

Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 psig.

SERVICE LINES: LOCATION OF VALVES (49 CFR 192.365)

- o Relation to regulator or meter. You must install each service-line valve upstream of the regulator. If there is no regulator, install the valve upstream of the meter. (See Figures IV-2 through IV-5.)

- o Outside valves. Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building. (See Figure IV-2.)

- o Underground valves. Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve. The box or standpipe must not put stress on the service line. (See Figures IV-3 and IV-4.)

Services should not be installed under buildings or mobile homes. If a service is installed under a building, it must be encased in a gas-tight conduit. This conduit must vent to the outside to a point where gas would not be a hazard, and extend above ground, terminating in a rain and insect resistant fitting.

COMMON PROBLEMS TO WATCH FOR AT SERVICE RISER AND HOUSE REGULATORS

- o Regulator vandalism or damage. This can be very hazardous. If the regulator fails to function for any reason, high pressure gas may enter the appliances. Tall flames at the burner or escape of gas could cause a fire or explosion.

- <u>Obstructed vents</u>. The vent on the regulator should be free of any obstructions. A wire screen installed at the vent should prevent the accumulation of dirt, the intentional insertion of foreign objects by children, or the build up of insect nests (e.g., wasp nests.) If the screen is removed, a new one must be inserted in its place. A non-functioning vent could cause regulator failure and thus present a serious fire hazard within the residential unit. The vent should be pointed down and away from windows and air intakes.

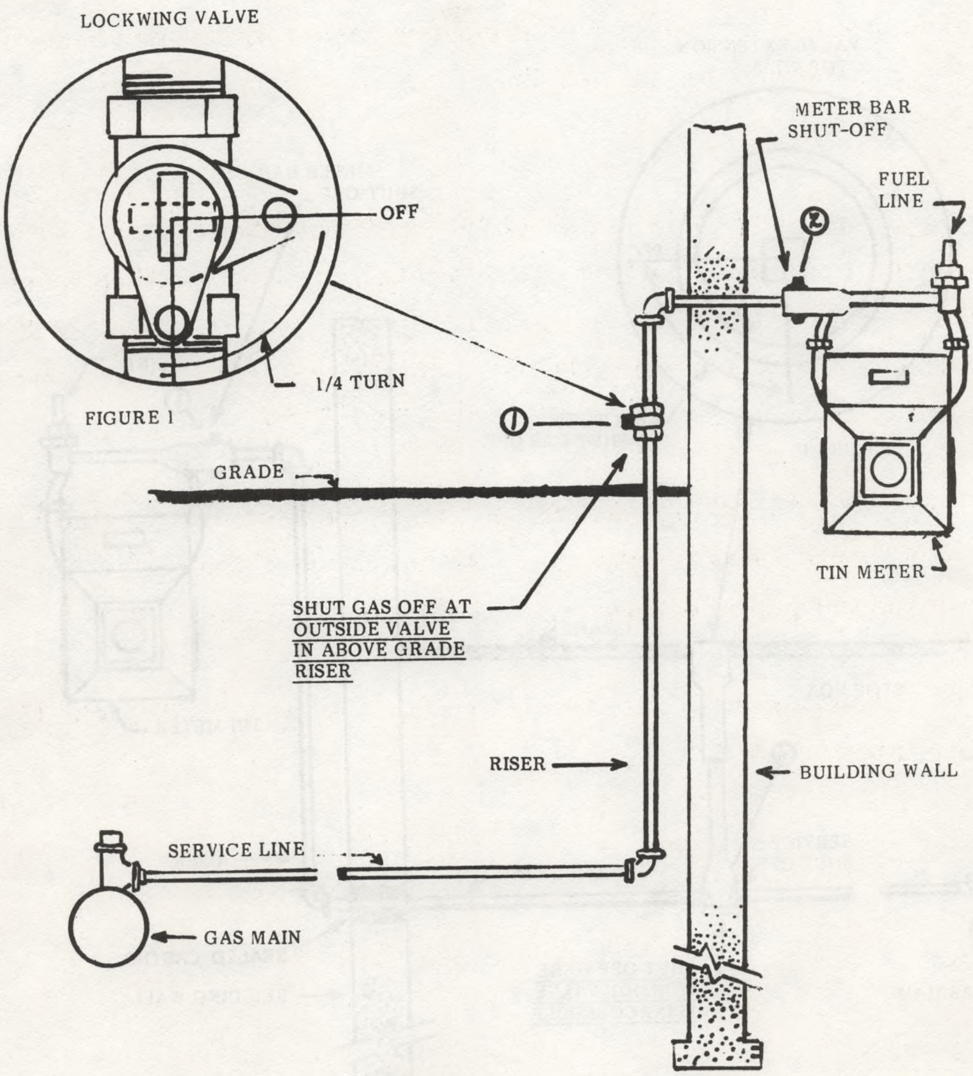
- <u>Tenant move out</u>. The valve on the meter riser should be equipped with a locking device to be controlled by authorized personnel only. When tenants move out, the gas is shut off and locked until new tenants move in. The locking device on the shutoff valve also allows the repair of appliances without fear of the gas being accidentally turned on.

- <u>Riser misuse</u>. The tenants or customers should not be allowed to use the riser and its components for other purposes. Never use as an anchor for laundry lines, plant supports, or bicycle racks. (See Appendix F, Figure 17.)

- <u>Corrosion</u>. Check for corrosion on the service riser at ground level. (See Appendix F, Figure 24.)

Figure IV-2

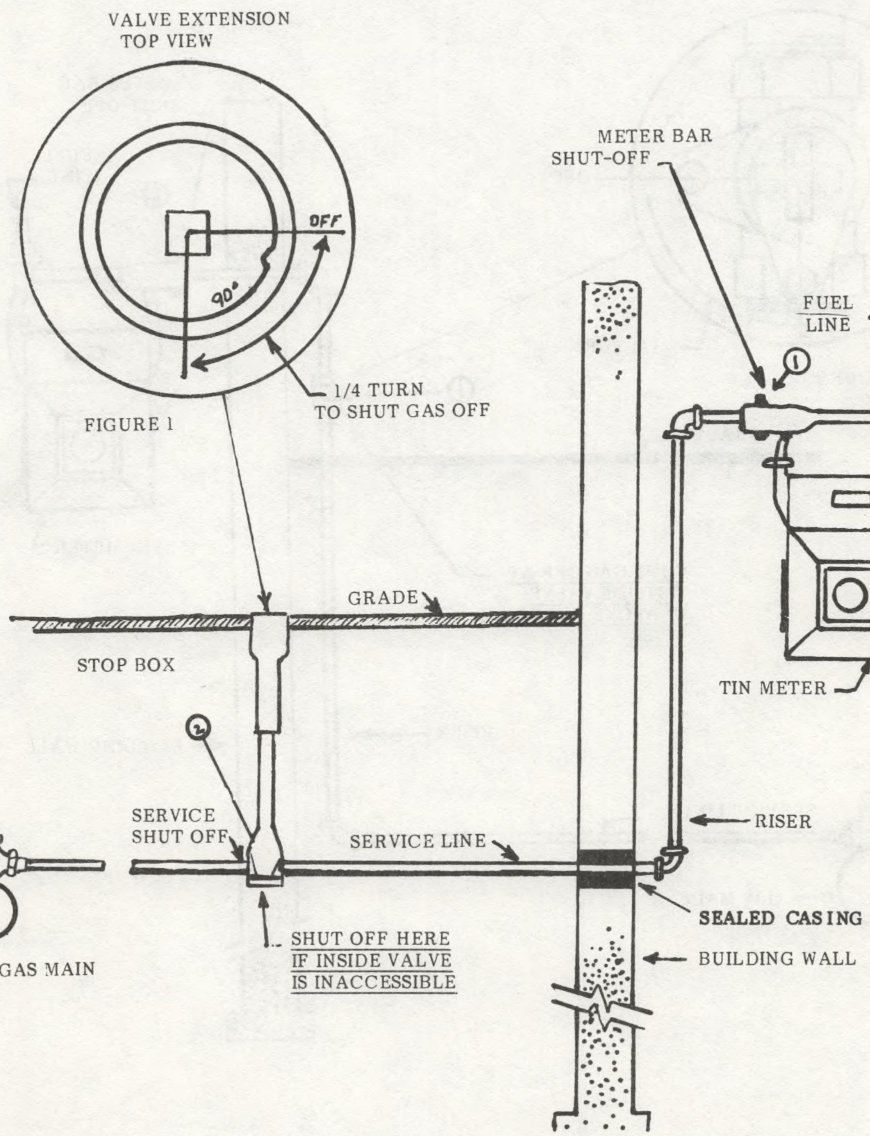
SERVICE LINES OPERATING AT LOW PRESSURE
OUTSIDE SHUT-OFF - INSIDE METER



This is a typical low pressure service (pressure in main and service are essentially the same as customer utilization pressure.) Note that this servi:x can be shut off at either (1) or (2) as shown on drawing. This service would be in compliance with 49 CFR 192.365. The valve at either point (1) or (2) must be designed so that it can be locked in a closed position.

Figure IV-3

SERVICE LINE OPERATING AT LOW PRESSURE BELOW GROUND OUTSIDE SERVICE VALVE

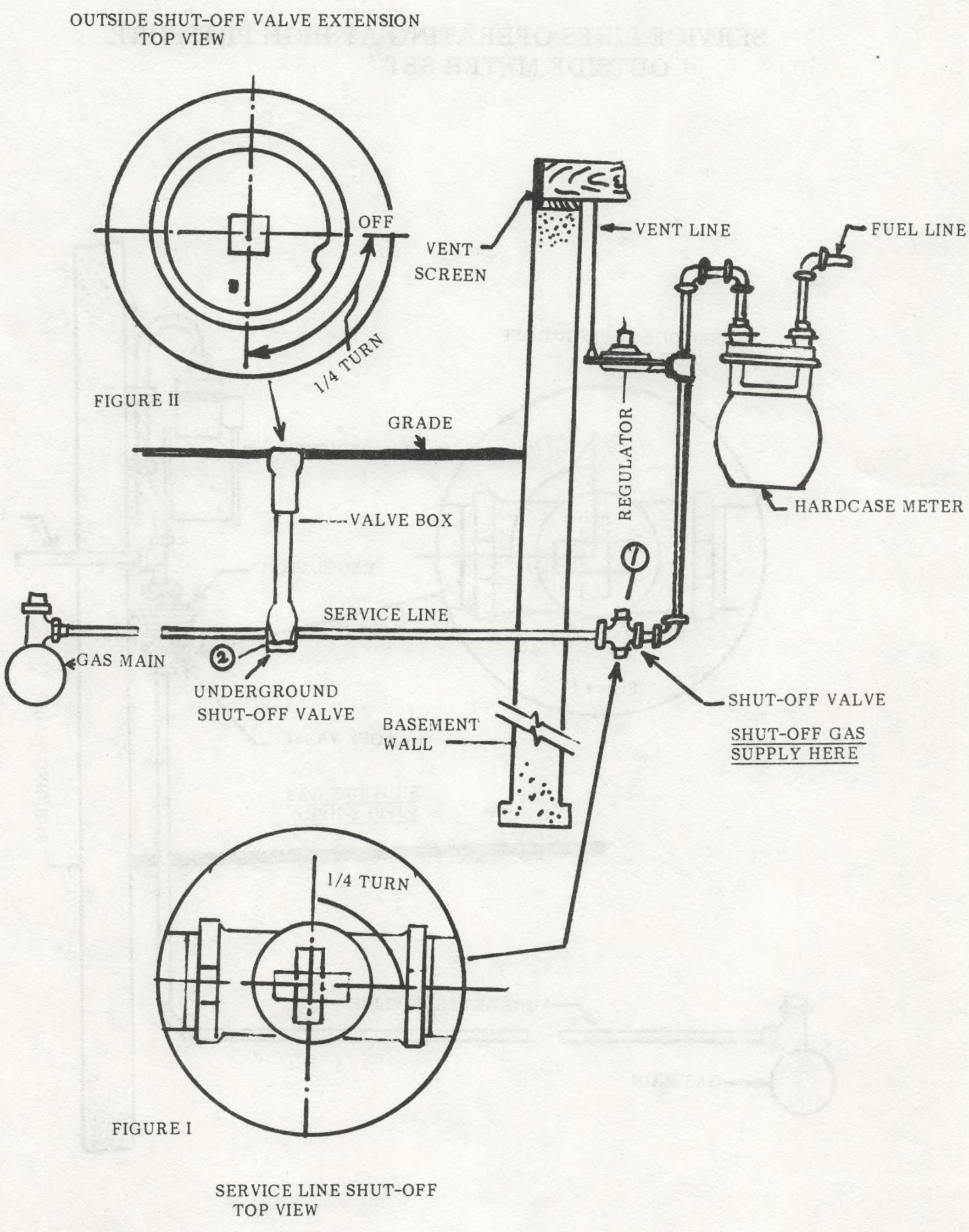


Note that this service can be shut off at either point (1) or (2). The valve at point (2) is installed in a valve box. The valve at point (1) must be designed so that it can be locked in a closed position.

Figure IV-4

SERVICE LINES OPERATING AT HIGH PRESSURE INSIDE METER SET

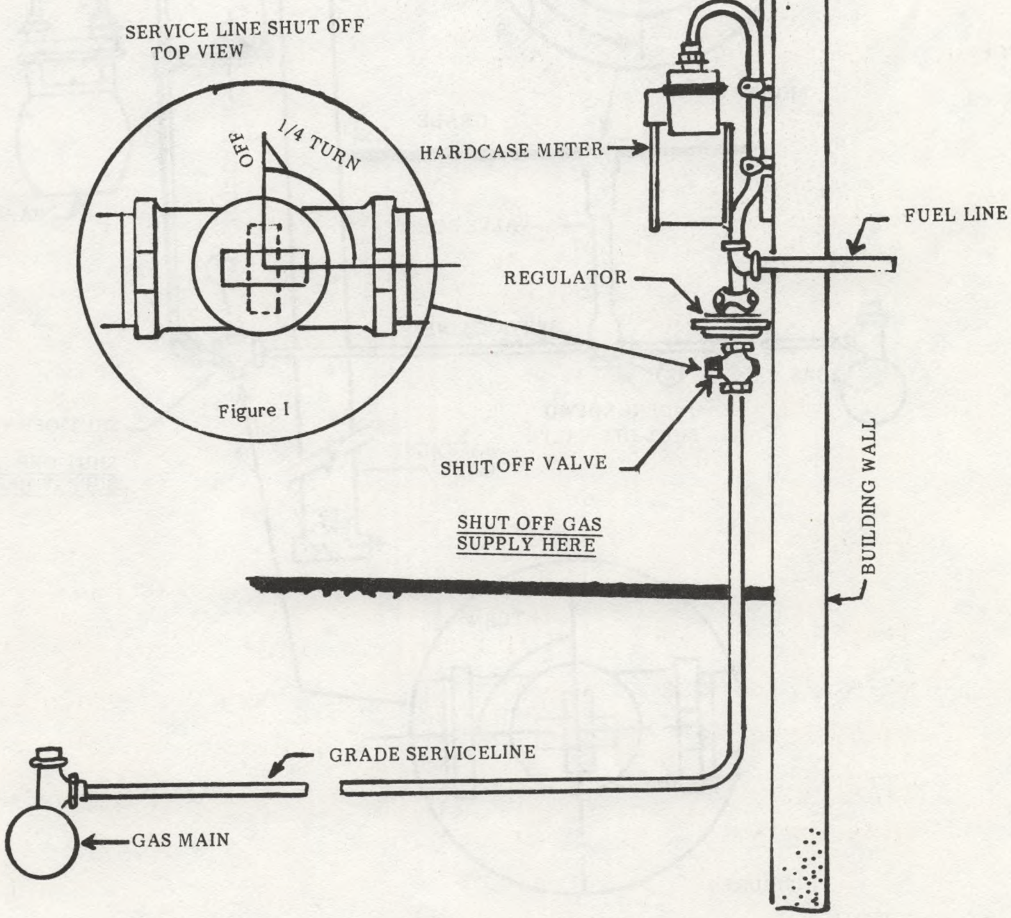
(below 60 psig)



The service can be shut off at either point (1) or (2). Note that the shut-off valve at point (1) is installed before the regulator. The valve at point (1) must be designed so that it can be locked in a closed position.

Figure IV-5

SERVICE LINES OPERATING AT HIGH PRESSURE OUTSIDE METER SET



Note that the shut-off valve is before the regulator and meter. This valve must be designed so that it can be locked in the closed position.

CHAPTER V

PLACES TO FIND ADDITIONAL INFORMATION

The local gas utilities are often the best source of information as to where to find local suppliers of gas pipeline components (pipe, valves, etc.). They may also be able to supply you with the names of good gas contractors to work on your system.

There are a number of gas and corrosion control magazines and journals that have useful information about material selection and operation and maintenance for small gas systems.

Three of these magazines publish "Buyers Guide Issues." The names of these magazines are:

- Pipeline and Gas Journal, "Buyers Guide Issue"

  Address: Energy Publications
  (a Division of Harcourt Brace Jovanovich)
  P.O. Box 1589
  Dallas, Texas 75221
  Phone: (214) 748-4403

  Comment

  The "Buyers Guide Issue" is published on an annual basis. "The Handbook and Buyers Guide Issue" contains the names and addresses of manufacturers of gas pipe, valves, welding equipment, etc. This issue also lists the suppliers of this equipment. It also lists a number of companies that specialize in cathodic protection surveys/engineering and leakage surveys.

- NACE Corrosion Engineering Buyers Guide

  Address: NACE
  P.O. Box 218340
  Houston, Texas 77218

Attention: Publication - Sales
Phone: (713) 492-0535
(Item No. 52144)

Comment

The NACE Corrosion Engineering Buyers Guide is published on an annual basis. The publication includes the following: products/services, directory of manufacturers, suppliers, and consultants serving the corrosion engineering field.

- o LP-Gas Magazine - "Buyers Guide"

  Address: Harcourt Brace Jovanovich Publications
  One East First Street
  Duluth, Minnesota 55802
  Phone: (218) 227-8511

Comment

March issue is the "Buyers Guide Issue."

Other gas magazines or journals that may be of interest:

- o Gas Industries

  Address: P.O. Box 1068
  Waukegan, Illinois 60085

- o Pipeline and Gas Journal

  Address: Energy Publications
  P.O. Box 1589
  Dallas, Texas 75221

- o Pipeline Industry

  Address: Gulf Publishing Co.
  P.O. Box 2608
  Houston, Texas 77001

Comment

These magazines contain pertinent articles on the operation, maintenance, and construction of gas systems. Materials, such as pipe, valves, and fittings, used in gas systems are heavily advertised in these magazines. In addition, schedules of gas related educational courses and meetings sponsored by industry are listed.

For detailed information about gas piping systems:

- The American Gas Association (AGA) is an excellent source of more general information about gas systems, materials, and gas safety publications, including Consumer Information Bill Stuffers. The address is:

  American Gas Association
  1515 Wilson Boulevard
  Arlington, Virginia 22209
  Phone: (703) 841-8400

- The National LP-Gas Association is an excellent source of information about LP-Gas. This association publishes the LP-Gas Safety Handbook. This handbook contains information about LP-Gas Distribution Operations, Emergency Procedures, Safety Meetings, etc. Cost in 1981 - $15.00. The address is:

  National LP-Gas Association
  1301 West 22nd Street
  Oak Brook, Illinois 60521
  Phone: (312) 986-4800

- ASME Guide for Gas Transmission and Distribution Piping Systems - 1983

  This guide contains design rules, material references, and other recommended practices, appropriately arranged and referenced to the federal gas pipeline safety regulations. This guide contains many detailed engineering formulas for design and materials. It details the procedures that represent current

state-of-the-art methods of complying with each regulation. It is an excellent source of information for a person with a technical or gas operating background and is continually updated. The address is:

The American Society of Mechanical Engineers
United Engineering Center
345 47th Street
New York, New York 10017
Phone: (212) 644-7805

o National Fire Protection Association, Inc. (NFPA).

The federal gas regulations incorporate by reference two (NFPA) standards regarding LP-Gas, NFPA 58 and NFPA 59. These standards can be obtained from NFPA at this address: Batterymarch Park, Quincy, Massachusetts 02269.

Other gas associations which may be of assistance include:

ALABAMA NATURAL GAS ASSOCIATION
P.O. Box 43063
Birmingham, Alabama 35243
Phone: (205) 870-0405

AMERICAN PUBLIC GAS ASSOCIATION
P.O. Box 1426
Vienna, Virginia 22180
Phone: (703) 281-2910

THE FLORIDA NATURAL GAS ASSOCIATION
815 Briercliff Drive
Orlando, Florida 32806

GUILD OF GAS MANAGERS
100 Weybosset Street
Providence, Rhode Island 02901

INDIANA GAS ASSOCIATION INC.
320 N Meridan Street - Room 501
Indianapolis, Indiana 46204
Phone: (317) 639-5418

THE LEAGUE OF KANSAS MUNICIPALITIES
112 W Seventh Street
Topeka, Kansas 66603

GAS APPLIANCE MANUFACTURERS
ASSOCIATION
1901 North Fort Myer Dr.,
Arlington, Virginia 22209

KANSAS MUNICIPAL UTILITIES INC
P.O. Box 1225,
McPherson, Kansas 67460

KENTUCKY GAS ASSOCIATION
Route 1, Box 30-A,
Winchester, Kentucky 40391

MID-CONTINENT OIL & GAS ASSOCIATION
711 Adams Office Bldg.,
Tulsa, Oklahoma 74103

MIDWEST GAS ASSOCIATION INC
1111 Douglas Drive
Minneapolis, Minnesota 55422
Phone: (612) 544-8272

MISSISSIPPI NATURAL GAS ASSOCIATION
512 Court Street
Jackson, Mississippi 39201
Phone: (601) 355-2300

NEW JERSEY UTILITIES
ASSOCIATION
1600 Pacific Avenue
Atlantic City, New Jersey 08404

NEW YORK GAS GROUP
500 Fifth Avenue
Suite #4120
New York, New York 10110
Phone: (212) 354-4790

OHIO GAS ASSOCIATION
17 S High Street - Room 811
Columbus, Ohio 43215
Phone: (614) 224-1036

NORTH TEXAS OIL & GAS
ASSOCIATION
1106 City National Bldg.
Wichita Falls, Texas 76301
Phone: (817) 723-4131

PACIFIC COAST GAS ASSOCIATION
1350 Bayshore Hwy, - Suite 340
Burlingame, California 94010

PENNSYLVANIA GAS ASSOCIATION
Locust Court - P. O. Box 805
Harrisburg, PA 17108-0805
Phone: (717) 233-5814

THE NEW ENGLAND GAS ASSOCIATION
1427 Statler Office Bldg,
Boston, Massachusets 02116
Phone: (617) 482-4277

ROCKY MOUNTAIN GAS ASSOCIATION
550 15th St, Rm 400,
Denver, Colorado 80202
Phone: (303) 571-7300

SOUTHEASTERN GAS ASSOCIATION
P.O. Box 5125
Raleigh, North Carolina 27650
Phone: (919) 737-2233

SOUTHERN GAS ASSOCIATION
4230 LBJ Freeway,
Suite 414,
Dallas, Texas 75234
Phone: (214) 387-8505

TEXAS GAS ASSOCIATION
10 Dawn Dr - P.O. Box 965
Lago Vista, Texas 78641
Phone: (512) 267-2933

TENNESSEE GAS ASSOCIATION
814 Church Street
Nashville, Tennessee 37203

WISCONSIN UTILITIES ASSOCIATION
P.O. Box 600
44 E Mifflin Street
Madison, Wisconsin 53701
Phone: (608) 257-3151

The U.S. Department of Transportation through the Transportation Safety Institute, Oklahoma City, Oklahoma, holds pipeline safety seminars in various states every year.

The schedule of these seminars and their locations can be obtained by calling the following telephone number: (405) 686-2466. The address is:

Transportation Safety Institute (Pipeline Safety)
6500 South MacArthur Boulevard DMA-65
Oklahoma City, Oklahoma 73125

Gas system operators may get assistance from state pipeline safety agencies. Activities conducted by these agencies will vary by state but may include seminars and the publication of educational material. (See Appendix A.)

Another source of assistance or information may be a local mobile home association.

APPENDIX A

STATE AGENCIES WITH JURISDICTION OVER PIPELINE SAFETY 1984

Alabama

Alabama Public Service Commission
444 S. Decatur Street
Montgomery, Alabama 36130
Phone: (205) 832-3410

Arizona

Arizona Corporation Commission
1210 W. Washington Street
Phoenix, Arizona 85007
Phone: (602) 255-4251

Arkansas

Arkansas Public Service Commission
P.O. Box 400C
Little Rock, Arkansas 72203
Phone: (501) 371-1054

California

California Public Utilities
Commission
California State Building
350 McAllister Street
San Francisco, California 94102
Phone: (415) 557-0519

Colorado

Colorado Public Utilities Commission
500 State Service Building
1525 Sherman Street
Denver, Colorado 80203
Phone: (303) 839-3182

Connecticut

Connecticut Department of Public
Utility Control
1 Central Park Plaza
New Britain, Connecticut 06051
Phone: (203) 827-1553

Delaware

Delaware Public Service Commission
1560 South DuPont Highway
Dover, Delaware 19901
Phone: (302) 678-4247

District of Columbia

District of Columbia Public Service
Commission
Room 220
451 Indiana Avenue, N.W.
Washington, D.C.
Phone: (202) 727-3050

Florida

Florida State Treasurer & Insurance
Commissioner
Division of LPG
1313 Tampa Street
Tampa, Florida 33602
Phone: (813) 272-2442

Florida

Florida Public Service Commission
Fletcher Building
101 East Gaines Street
Tallahassee, Florida 32304
Phone: (904) 488-8501

Georgia

Georgia Public Service Commission
162 State Office Building
244 Washington Street, S.W.
Atlanta, Georgia 30334
Phone: (404) 656-4518

Hawaii

Hawaii Public Utilities Division
Department of Regulatory Agencies
P.O. Box 541
Honolulu, Hawaii 96809
Phone: (808) 548-7550

Illinois

Illinois Commerce Commission
527 East Capitol Avenue
Springfield, Illinois 62706
Phone: (217) 785-8398

Indiana

Indiana Public Service Commission
901 State Office Building
Indianapolis, Indiana 46204
Phone: (317) 633-4853

Iowa

Iowa State Commerce Commission
State Capitol
Des Moines, Iowa 50319
Phone: (515) 281-5546

Kansas

Kansas State Corporation Commission
State Office Building
Topeka, Kansas 66612
Phone: (913) 296-4192

Kentucky

Kentucky Public Service Commission
P. O. Box 615
Frankfort, Kentucky 60402
Phone: (502) 564-7599

Louisiana

Louisiana Department of Natural Resources
P.O. Box 44275
Capitol Station
Baton Rouge, Louisiana 70804
Phone: (504) 342-5540

Maine

Maine Public Utilities Commission
State House
242 State Street
Augusta, Maine 04333
Phone: (207) 289-3831

Maryland

Maryland Public Service Commission
The American Building, 11th Floor
231 East Baltimore Street
Baltimore, Maryland 21201
Phone: (301) 659-6085

Massachusetts

Massachusetts Department of Public Utilities
Saltonstall Building, Room 1208
100 Cambridge Street
Boston, Massachusetts 02202
Phone: (617) 727-3537

Michigan

Michigan Public Service Commission
P.O. Box 30221
Lansing, Michigan 48909
Phone: (517) 373-3267

Minnesota

Minnesota Department of Public Safety
State Fire Marshal Division
1246 University Avenue
St. Paul, Minnesota 55104
Phone: (612) 296-7647

Mississippi

Mississippi Public Service Commission
P.O. Box 1174
Jackson, Mississippi 39205
Phone: (601) 354-7587

Missouri

Missouri Pubic Service Commission
P.O. Box 360
Jefferson City, Missouri 65102
Phone: (314) 751-3456

Montana

Montana Public Service Commission
1227-11th Avenue
Helena, Montana 59601
Phone: (406) 449-3456

Nebraska

Nebraska State Fire Marshal
301 Centennial Building
P.O. Box 94677
Lincoln, Nebraska 68509
Phone: (402) 471-2027

Nevada

Nevada Public Service Commission
505 East King Street
Carson City, Nevada 89701
Phone: (702) 885-5134

New Hampshire

New Hampshire Public Utilities
Commission
Building #1
8 Old Suncook Road
Concord, New Hampshire 03301
Phone: (603) 271-2431

New Jersey
New Jersey Board of Public Utilities
Bureau of Pipeline Safety
101 Commerce Street
Newark, New Jersey 07102
Phone: (201) 648-2272

New Mexico

New Mexico State Corporation
Commission
P.O. Drawer 1269
Santa Fe, New Mexico 87501
Phone: (505) 827-2163

New York

New York Public Service
Commission
Empire State Plaza
Agency Building #3, 12th Floor
Albany, New York 12223
Phone: (518) 474-5454

North Carolina

North Carolina Utilities Commission
P.O. Box 991
430 N. Salisbury Street
Raleigh, North Carolina 27602
Phone: (919) 733-6000

North Dakota

North Dakota Public Service
Commission
State Capitol Building
Bismarck, North Dakota 58501
Phone: (701) 224-2400

Ohio

Ohio Public Service Commission
375 South High Street
Columbus, Ohio 43215
Phone: (614) 466-7542

Oklahoma

Oklahoma Corporation Commission
Jim Thorpe Office Building
Oklahoma City, Oklahoma 73105
Phone: (405) 521-2258 or 3952

Oregon

Oregon Public Utility Commission
Labor & Industries Building, #300
Salem, Oregon 97310
Phone: (503) 378-6628

Pennsylvania

Pennsylvania Public Utility
Commission
Bureau of Safety Compliance
P.O. Box 3265
Harrisburg, Pennsylvania 17120
Phone: (717) 787-1061

Puerto Rico

Puerto Rico Public Service Commission
P.O. Box "CP"
Hato Rey, Puerto Rico 00919
Phone: (809) 763-5077

Rhode Island

Rhode Island Public Utilities Commission
Division of Public Utilities and Carriers
100 Orange Street
Providence, Rhode Island 02903
Phone: (401) 277-3500

South Carolina

South Carolina Public Service Commission
P.O. Box 11649
Columbia, South Carolina 29211
Phone: (803) 758-2342

Tennessee

Tennessee Public Service Commission
Cordell Hull Building, C1-102
Nashville, Tennessee 37219
Phone: (615) 741-2844

Texas

Texas Railroad Commission
Drawer 12967
Capitol Station
Austin, Texas 78711
Phone: (512) 445-1144

Utah

Utah Public Service Commission
330 East 4th South Street
Salt Lake City, Utah 84111
Phone: (801) 533-5517

Vermont

Vermont Department of Public Service
State Office Building
120 State Street
Montpelier, Vermont 05602
Phone: (802) 828-2811

Virginia

Virginia State Corporation Commission
Division of Energy Regulation
Blanton Building - P.O. Box 1197
Richmond, Virginia
Phone: (804) 786-4264

Washington

Washington Utilities & Transportation Commission
Highways-Licenses Building
Olympia, Washington 98504
Phone: (206) 753-6415

West Virginia

West Virginia Public Service Commission
3324 MacCorkle Avenue, S.E.
Charleston, West Virginia 25304
Phone: (304) 348-2167

Wisconsin

Wisconsin Public Service Commission
P.O. Box 7854
Madison, Wisconsin 53707
Phone: (608) 266-3491

Wyoming

Wyoming Public Service Commission
320 West 25th Street
Cheyenne, Wyoming 82002
Phone: (307) 777-7427

DEPARTMENT OF TRANSPORTATION
MATERIALS TRANSPORTATION BUREAU
OFFICE OF OPERATIONS AND ENFORCEMENT
(PIPELINE SAFETY)

Central Region
911 Walnut Street
Kansas City, Missouri 64106
Phone: (816) 374-2654

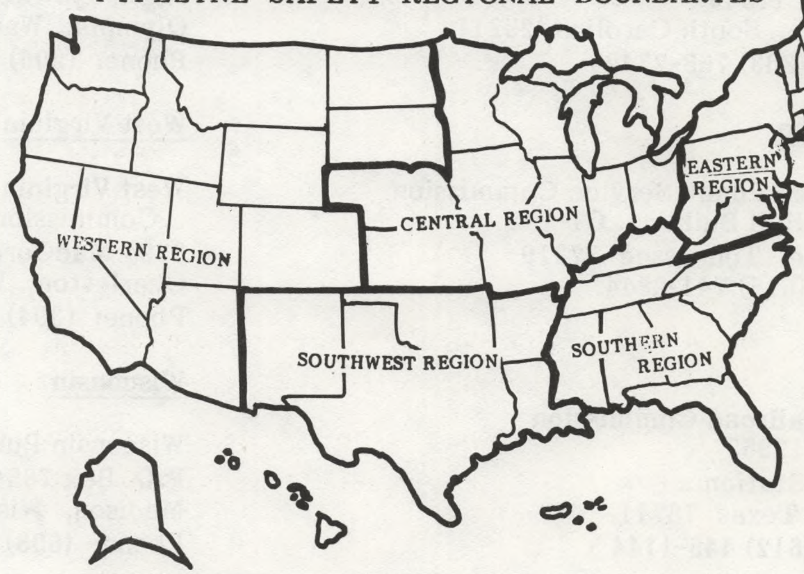
Eastern Region
400 Seventh Street, S.W.
Washington, D.C. 20590
Phone: (202) 755-9435

Western Region
555 Zang Street
Lakewood, Colorado 80228
Phone: (303) 234-2313

Southern Region
Suite 505 North
1776 Peachtree Road, N.W.
Atlanta, Georgia 30309
Phone: (404) 881-2632

Southwest Region
2320 LaBranch
Houston, Texas 77004
Phone: (713) 750-1746

MATERIALS TRANSPORTATION BUREAU
PIPELINE SAFETY REGIONAL BOUNDARIES



The federal government's Materials Transportation Bureau has five regional offices. If you need help in understanding the federal requirements, you should contact the regional office that has pipeline safety jurisdiction for your state (see map.) Before contacting the federal regional office, it is a good practice to call your respective state agency listed in this Appendix.

APPENDIX B
METHODS OF GAS LEAK DETECTION

This appendix gives you eight warning signs of a gas leak, describes leak detection equipment, and recommends methods for conducting surface and subsurface leak detection surveys.

WARNING SIGNS OF A LEAK

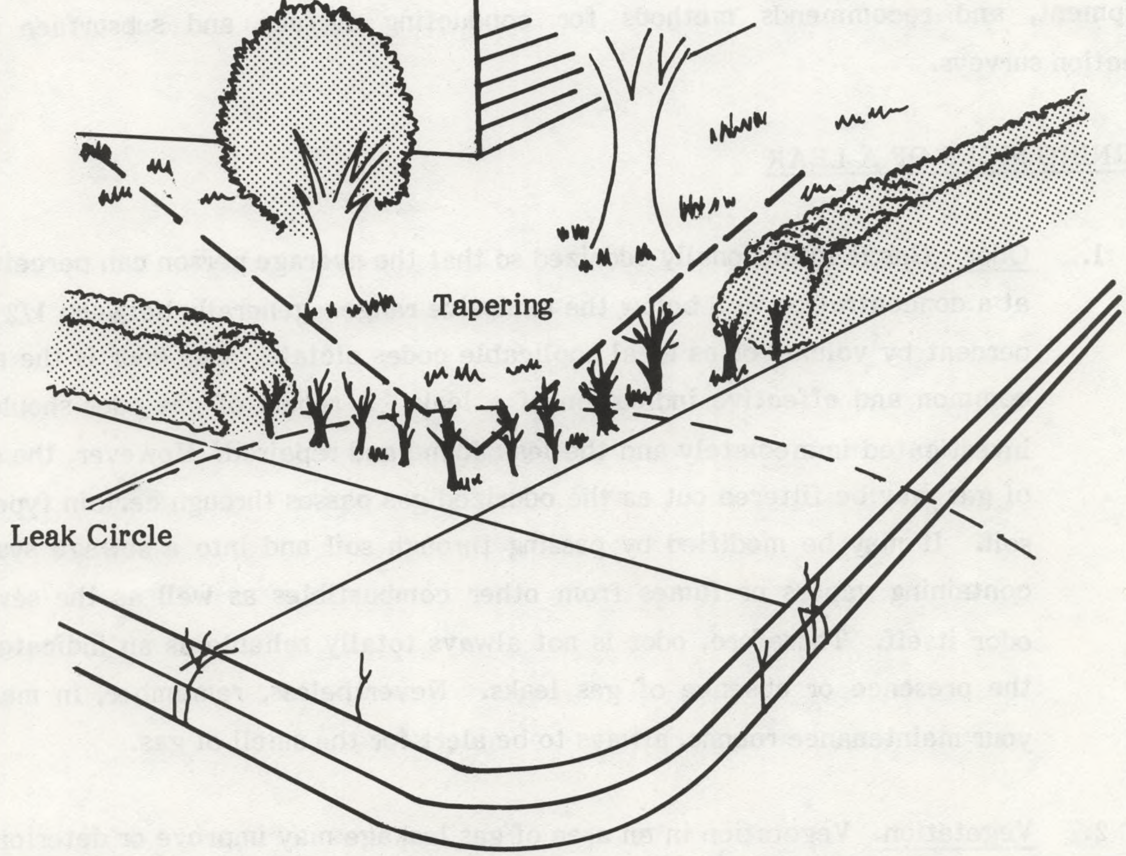
1. Odor. Gas is intentionally odorized so that the average person can perceive it at a concentration well below the explosive range - generally between 1/2 to 1 percent by volume or as local applicable codes dictate. Gas odor is the most common and effective indication of a leak. A report of gas odor should be investigated immediately and the leak found and repaired. However, the odor of gas may be filtered out as the odorized gas passes through certain types of soil. It may be modified by passing through soil and into a sewage system containing vapors or fumes from other combustibles as well as the sewage odor itself. Therefore, odor is not always totally reliable as an indicator of the presence or absence of gas leaks. Nevertheless, remember, in making your maintenance rounds, always to be alert for the smell of gas.

2. Vegetation. Vegetation in an area of gas leakage may improve or deteriorate, depending on the soil, the type of vegetation, the environment, the climate, and the volume and duration of the leak. Vegetation surveys of changes in vegetation may indicate slow sub-soil leaks. Vegetation surveys should be supplemented with instrumentation. See Figures B-1 and B-2.

3. Insects (flies, roaches, spiders.) Insects migrate to points or areas of leakage due to microbial breakdown of some components of gas. Some insects seem to like the smell of the gas odorant. Keep your eyes open for heavy insect activity, particularly near the riser, the gas meter, and regulator.

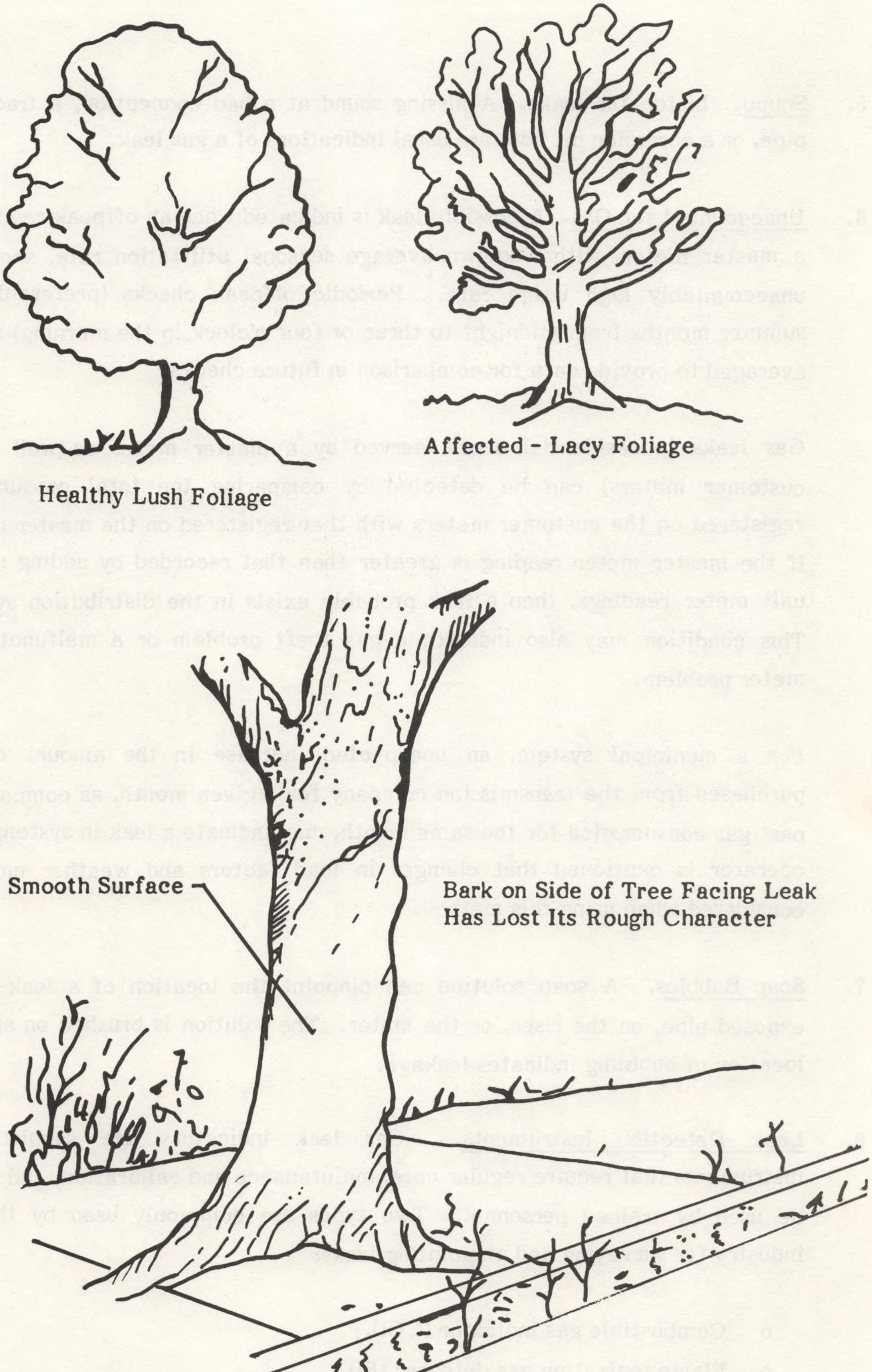
4. Fungus-Like Growth. Such growth in valve boxes, manholes, etc., indicates gas leakage. The color of the growth is generally white or grayish-white and looks like a coating of frost.

Figure B-1



EFFECT OF GAS LEAKAGE IN A GAS MAIN ON A HEDGE

Figure B-2



USE OF TREES AS GAS LEAK INDICATORS

5. Sound. Listen for leaks. A hissing sound at a bad connection, a fractured pipe, or a corrosion pit hole are usual indications of a gas leak.

6. Unaccounted for Gas. A possible leak is indicated when an offpeak reading of a master meter, with a known average seasonal utilization rate, shows an unaccountably high usage rate. Periodic offpeak checks (preferably the summer months from midnight to three or four o'clock in the morning) can be averaged to provide data for comparison in future checks.

   Gas leaks in residential areas (served by a master meter as well as by customer meters) can be detected by comparing the total consumption registered on the customer meters with that registered on the master meter. If the master meter reading is greater than that recorded by adding all the unit meter readings, then a leak probably exists in the distribution system. This condition may also indicate a gas theft problem or a malfunctioning meter problem.

   For a municipal system, an unexpected increase in the amount of gas purchased from the transmission company for a given month, as compared to past gas consumption for the same month, may indicate a leak in system. The operator is cautioned that changes in load factors and weather must be considered when using this method.

7. Soap Bubbles. A soap solution can pinpoint the location of a leak on an exposed pipe, on the riser, or the meter. The solution is brushed on and the location of bubbling indicates leakage.

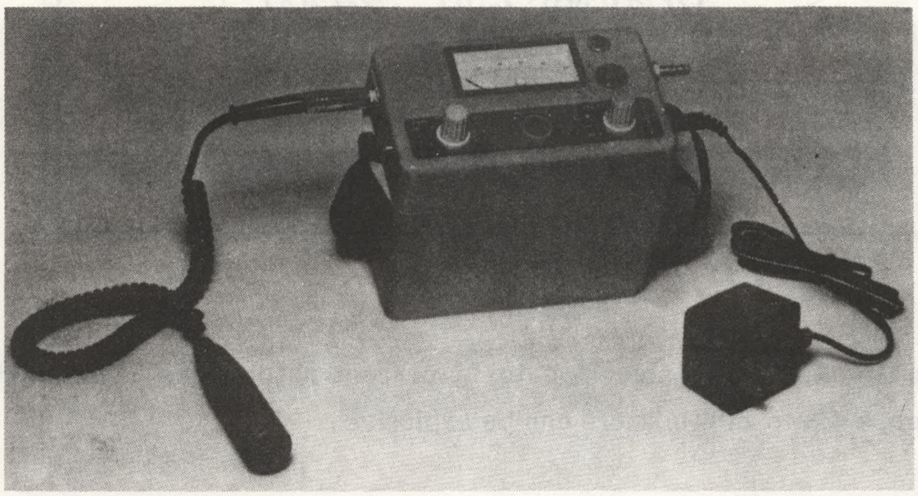
8. Leak Detection Instruments. Gas leak indicators are sophisticated instruments that require regular care, maintenance and calibration, and should be used by trained personnel. Two types are commonly used by the gas industry for surveying and pinpointing leaks:

   o Combustible gas indicator (CGI).
   o Flame ionization gas detector (FI).

DESCRIPTION OF LEAK DETECTION EQUIPMENT

Combustible gas indicator. The combustible gas indicator (CGI) (Figure B-3) consists of a meter, a probe, and a rubber bulb. The bulb is pumped by hand to bring a sample of air into the probe and the instrument. The dial on the instrument indicates the percentage of flammable gas in air or percent of the lower explosive limit (LEL). These instruments must be calibrated for the type of gas in system. If you have a natural gas system, the CGI should be calibrated for natural gas. If your system is LP-Gas, the CGI that you use should be calibrated for the type of LP-Gas in system (propane, butane, etc.)

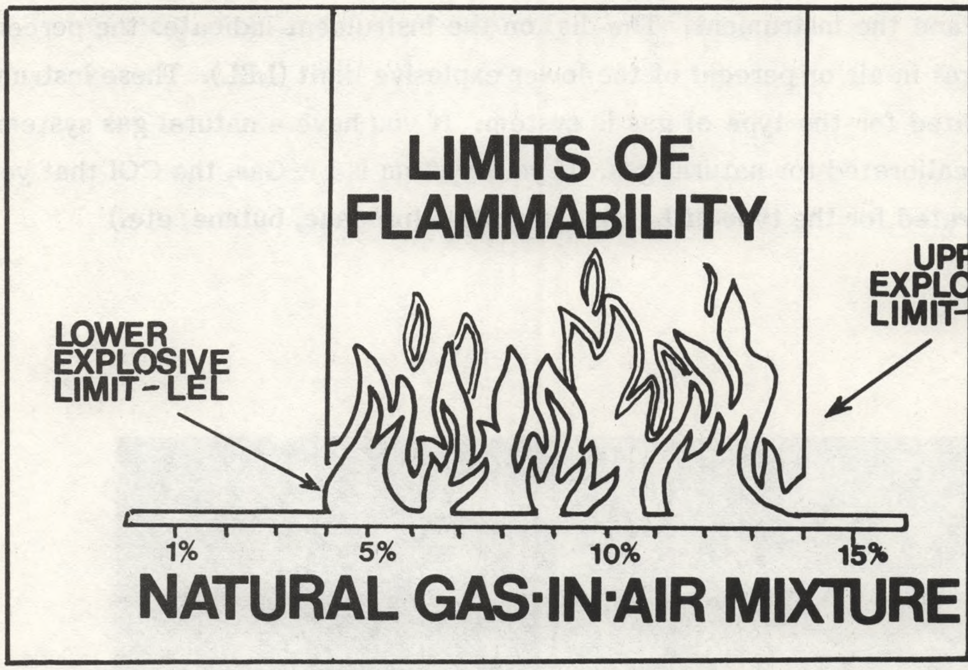
Figure B-3



This is a picture of a combustible gas indicator (CGI). MTB recommends that a two scale meter be purchased (LEL (lower explosive limit) and percent gas.)

Figure B-4 is an illustration of the upper and lower explosive limits for natural gas.

Figure B-4



Typical natural gas is flammable in 4 to 14 percent natural gas in air mixture. In a confined space, a 4% to 14% mixture can be explosive.

Table 1 lists the upper and lower explosive limits for LP-gases.

Table 1

Limits of flammability in air, percent of LP-Gas vapor in air/gas mixture. At this percent the mixture will burn, or may explode if in a confined space.

	Commercial Propane NLPGA Ave.	Commercial Butane NLPGA Ave.
Lower	2.15 percent	1.55 percent
Upper	9.60 percent	8.60 percent

The CGI is not suitable for sampling unconfined air over a pipeline or near the ground surface. The CGI was designed primarily for use in a confined space. Its two main applications for outside surveys are termed "available openings" and "bar-holing." A bar hole is a small diameter hole made in the ground in the vicinity of gas piping to extract a sample of the ground atmosphere for leak analysis.

CGI instruments are also useful in building surveys and areas within the building, such as heater closets, and other confined areas.

The CGI can be operated by one person. Leak location is accurate and minimum training is necessary to use the instrument. The cost of a CGI is approximately $400 to $500. This is substantially cheaper than a Flame Ionization Unit.

Flame ionization unit. Caution: LP operators should not use a flame ionization unit as the sole means of determining gas leakage on their underground piping system.

The flame ionization process consists of a hydrogen-air source, a flame jet, two electrodes and an electrometer. During operation, a hydrogen flame is ignited at the flame jet and the electrodes collect a small current which is generated when combustible materials in the sample gas enter the hydrogen air flame. The electrometer amplifies this current for meter readouts, alarm signals or both.

The units can be hand carried (Figure B-5) or mounted on a vehicle. These instruments are extremely sensitive. These units have sensitivity range selections from 0 to 5,000 parts per million (PPM) or 10,000 PPM (methane in air). The cost of a FI unit is approximately $3,000.

The units are popular with large and medium size natural gas operators because of the unit's sensitivity and because a leakage survey over their system can be conducted in a much shorter time than by using a CGI bar holing method. However, an FI unit can not pinpoint underground leak locations. This means once an FI unit picks up a gas indication, a CGI unit may still be needed to pinpoint the leak.

Operators of FI units require more training than CGI operators. Also, FI units are more difficult to maintain. If an operator of a small gas system must make a choice between an FI unit and a CGI unit, MTB recommends that the operator purchase a CGI unit.

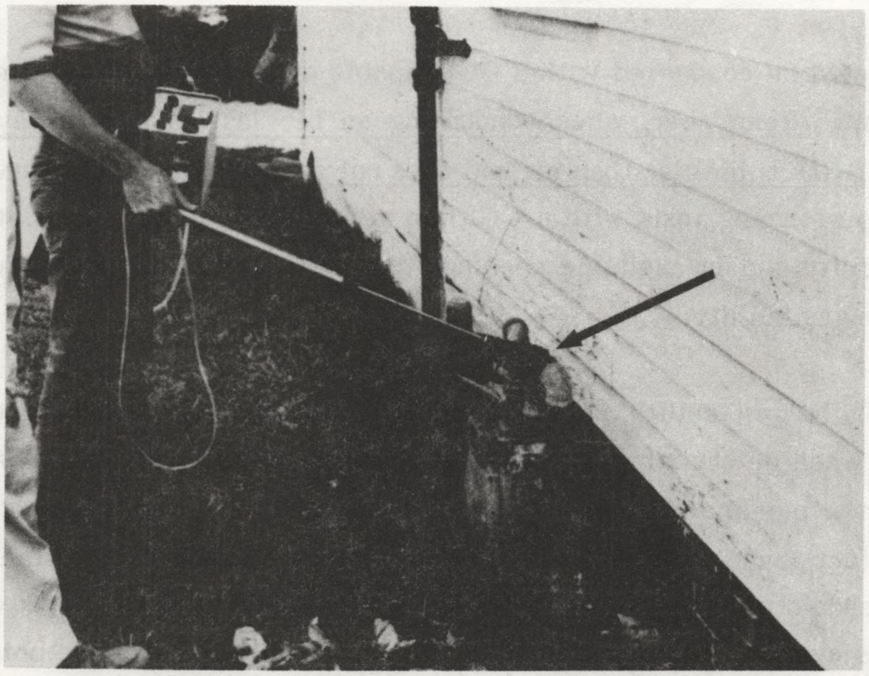
Instead of purchasing an FI unit, an operator can rely on a consultant, or hire a leak survey contractor to run FI surveys directly over the line being surveyed.

Suggested schedules for leakage surveys for operators of small gas systems are contained in Chapter I of this manual.

Figure B-5

This man is using a hand carried flame ionization unit.

Figure B-6



This man is checking a gas meter for leaks with a hand carried FI unit.

RECOMMENDED METHOD FOR SURFACE GAS DETECTION SURVEY WITH FI UNIT (NATURAL GAS SYSTEM ONLY)

A continuous sampling of the atmosphere at buried main and services should be made at ground level, or at no more than 2 inches above the ground surface. In areas where the gas piping is under pavement, samplings should also be at curb line(s), available ground surface openings (such as manholes, catch basins, sewer, power, and telephone duct openings, fire and traffic signal boxes or cracks in the pavement or sidewalk), or other interfaces where the venting of gas is likely to occur. For exposed piping, sampling should be adjacent to the piping.

For LP-Gas systems, the only method for a leak detection survey that is recommended by MTB is a subsurface gas survey using a CGI unit with a bar-hole survey.

RECOMMENDED METHOD FOR SUBSURFACE GAS DETECTION SURVEY WITH CGI (NATURAL GAS OR LP-GAS SYSTEM)

This survey should be conducted with a CGI capable of detecting 10 percent of the LEL at sample point. Remember, when conducting an LP-Gas leakage survey that unlike natural gas, LP-Gas is heavier than air and does not generally rise. The survey should be conducted by performing tests with a CGI in a series of bar holes immediately adjacent to the gas facility and in available openings (confined spaces and small substructures) adjacent to the gas facility.

The location of the gas facility and its proximity to buildings and other structures should be considered when determining the spacing of sample points. Spacing of sample points along the main or pipeline will depend on soil and surface conditions but should never be more than 20 feet apart. Where the facility passes under paving for a distance of 20 feet or less, tests should be made at the entrance and exit points of the paved area. Where the paved area over the facility is 20 feet or greater in length, sample points should be located at intervals of 20 feet or less.

In the case of extensive paving, permanent test points should be considered, particularly in low places. The sampling pattern should include tests at potential leak locations, such as threaded or mechanical joints, and at building walls at the service riser or service line entrance. All available openings adjacent to the facility should be tested.

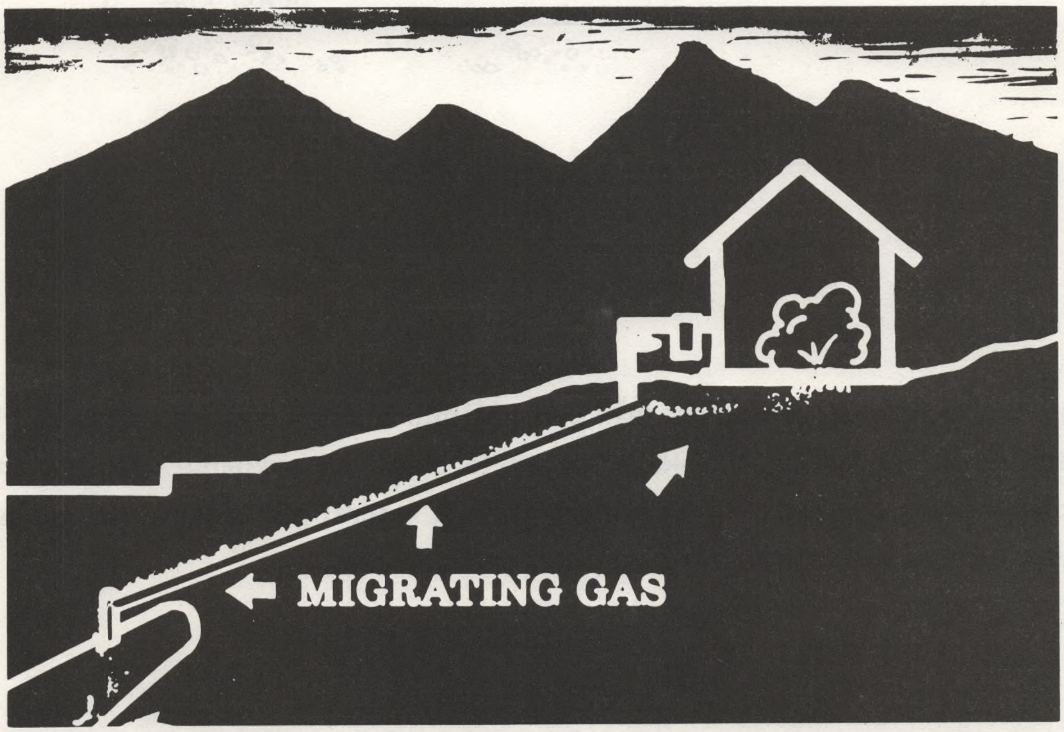
When testing available openings for LP-Gas, readings should be taken at both the top and bottom of the structure. When testing larger confined spaces or basements, the floor areas, including floor drains, should be tested thoroughly because gases can lie temporarily in pockets and become explosive mixtures. Since migrating gas may not enter at the pipeline entrance, a perimeter survey of the floors and walls is recommended. (See Figures B-7 and B-8).

When conducting the survey, if possible all bar holes should penetrate to the pipe depth in order to obtain consistent and accurate readings. The required depth of the test hole will depend upon the soil conditions, the depth of and pressure in the pipeline, and the type of instrument being used. The reading should be taken at the bottom of the test hole. The probe used should be equipped with a device to prevent the drawing in of fluids.

When conducting the survey, the inspector should use the most sensitive scale on the instrument, watching for small indications of combustible gas. Any indication should be further investigated to determine the source of the gas. Care should be taken to avoid damaging the pipe and/or coating with the probe bar.

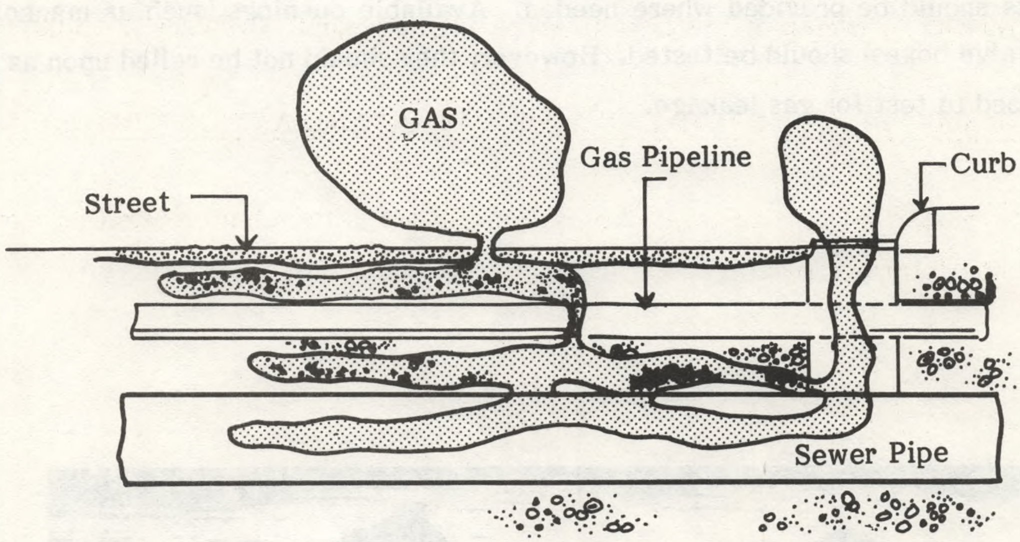
This survey method should be utilized for buried facilities. Good judgment must be used to determine when the recommended spacing of sample points is adequate. Additional sample points should be provided where needed. Available openings (such as manholes, vaults, and valve boxes) should be tested. However, they should not be relied upon as the only points used to test for gas leakage.

Figure B-7



Notice how the leaking gas followed service line and entered home. Both natural and LP-Gas can migrate in this manner.

Figure B-8



This is an example of how a gas leak can get into a sewer system. This is why it is essential when conducting a leakage survey to check all available openings, including manholes, sewers, vaults, etc. This illustration is natural gas because the gas is rising; however, LP-Gas will also migrate in sewers and manholes.

RECORDS

Operators must record all leakage surveys and must record all repair data. There is a sample form in Appendix C that may be used. Remember that you as an operator can develop your own forms. (See Form 2, Appendix C.)

Your records must include leak reports received from your customers or tenants. A sample form for the recording of these leak reports is in Appendix C, Form 12 and 3.

ASME - GUIDE MATERIAL FOR "LEAK CLASSIFICATION AND ACTION CRITERIA"

ASME has developed guide material for "Leak Classification and Action Criteria" illustrated on the following page.

TABLE 3a – LEAK CLASSIFICATION AND ACTION CRITERIA – GRADE 1

GRADE	DEFINITION	ACTION CRITERIA	EXAMPLES
1	A leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous.	Requires *prompt action* * to protect life and property, and continuous action until the conditions are no longer hazardous. *The prompt action in some instances may require one or more of the following. a. Implementation of company emergency plan (192.615). b. Evacuating premises. c. Blocking off an area. d. Rerouting traffic. e. Eliminating sources of ignition. f. Venting the area. g. Stopping the flow of gas by closing valves or other means. h. Notifying police and fire departments.	1. Any leak which, in the judgment of operating personnel at the scene, is regarded as an immediate hazard. 2. Escaping gas that has ignited. 3. Any indication of gas which has migrated into or under a building, or into a tunnel. 4. Any reading at the outside wall of a building, or where gas would likely migrate to an outside wall of a building. 5. Any reading of 80% LEL, or greater, in a confined space. 6. Any reading of 80% LEL, or greater in small substructures (other than gas associated substructures) from which gas would likely migrate to the outside wall of a building. 7. Any leak that can be seen, heard, or felt, and which is in a location that may endanger the general public or property.

TABLE 3b – LEAK CLASSIFICATION AND ACTION CRITERIA – GRADE 2

GRADE	DEFINITION	ACTION CRITERIA	EXAMPLES
2	A leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard.	Leaks should be repaired or cleared within one calendar year, but no later than 15 months from the date the leak was reported. In determining the repair priority, criteria such as the following should be considered. a. Amount and migration of gas. b. Proximity of gas to buildings and subsurface structures. c. Extent of pavement. d. Soil type, and soil conditions (such as frost cap, moisture and natural venting). Grade 2 leaks should be reevaluated at least once every six months until cleared. The frequency of reevaluation should be determined by the location and magnitude of the leakage condition. Grade 2 leaks may vary greatly in degree of potential hazard. Some Grade 2 leaks, when evaluated by the above criteria, may justify scheduled repair within the next 5 working days. Others will justify repair within 30 days. During the working day on which the leak is discovered, these situations should be brought to the attention of the individual responsible for scheduling leak repair. On the other hand, many Grade 2 leaks, because of their location and magnitude, can be scheduled for repair on a normal routine basis with periodic reinspection as necessary.	A. *Leaks Requiring Action Ahead of Ground Freezing or Other Adverse Changes in Venting Conditions* Any leak which, under frozen or other adverse soil conditions, would likely migrate to the outside wall of a building. B. *Leaks Requiring Action Within Six Months* 1. Any reading of 40% LEL, or greater, under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak. 2. Any reading of 100% LEL, or greater, under a street in a wall-to-wall paved area that has significant gas migration and does not qualify as a Grade 1 leak. 3. Any reading less than 80% LEL in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard. 4. Any reading between 20% LEL and 80% LEL in a confined space. 5. Any reading on a pipeline operating at 30 percent SMYS, or greater, in a class 3 or 4 location, which does not qualify as a Grade 1 leak. 6. Any reading of 80% LEL, or greater, in gas associated substructures. 7. Any leak which, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair.

TABLE 3c – LEAK CLASSIFICATION AND ACTION CRITERIA – GRADE 3

GRADE	DEFINITION	ACTION CRITERIA	EXAMPLES
3	A leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.	These leaks should be reevaluated during the next scheduled survey, or within 15 months of the date reported, whichever occurs first, until the leak is regraded or no longer results in a reading.	*Leaks Requiring Reevaluation at Periodic Intervals* 1. Any reading of less than 80% LEL in small gas associated substructures. 2. Any reading under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building. 3. Any reading of less than 20% LEL in a confined space.

FOLLOW-UP INSPECTION

The adequacy of leak repairs should be checked before backfilling. The perimeter of the leak area should be checked with a CGI. Where there is residual gas in the ground after the repair of a Class 1 leak, a follow-up inspection should be made as soon as practical after allowing the soil atmosphere to vent and stabilize. MTB suggests follow-up inspection within 24 to 48 hours, but in no case later than 1 month following the repair. In the case of other leak repairs, the need for a follow-up inspection should be determined by qualified personnel.

APPENDIX C
SAMPLE FORMS

GENERAL MAINTENANCE SCHEDULE

			JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.
1.	PATROL TRANSMISSION LINES	192.705												
2.	PATROL RIVER CROSSING, RAILROAD AND HIGHWAY CROSSING	192.705												
3.	GAS LEAK DETECTION SURVEYS	192.723												
	*DOWNTOWN BUSINESS AREAS	192.723												
	DISTRIBUTION MAINS AND SERVICES	192.723												
4.	*PRESSURE REGULATING STATIONS	192.739												
5.	*REGULATOR STATIONS, RECORDING OF PRESSURES	192.741												
6.	PRESSURE RELIEF VALVES	192.743												
8.	VALVE MAINTENANCE, DISTRIBUTION LINES	192.747												
9.	*ODORIZATION OF GAS	192.625												
10.	CORROSION CONTROL (EXTERNAL)	192.465												
11.	CORROSION CONTROL (ATMOSPHERIC)	192.481												
12.	CORROSION CONTROL (EXAMINATION)	192.459	EXAMINATION AND RECORD OBSERVATIONS ANYTIME BURIED PIPING IS EXPOSED											
13.	CORROSION CONTROL (RECTIFIERS)	192.465												
14.	TESTING OF PIPING	192.501 TO 192.517	TEST AND RECORD NEW PIPE INSTALLATION OR CONNECTIONS PER THIS SECTION											

NOTE: SHADE IN MONTH YOU INTEND TO PERFORM WORK AND POST IN A PROMINENT PLACE AS A REMINDER

* MAY NOT APPLY TO SMALL MASTER METER OPERATORS

GENERAL MAINTENANCE SCHEDULE

1.	*PATROL TRANSMISSION LINES	192.705	USE FORM 4
2.	PATROL RIVER CROSSINGS, RAILROAD AND HIGHWAY CROSSINGS	192.705	USE FORM 4
3.	GAS LEAK DETECTION SURVEYS	192.723	USE FORM 3
	*DOWNTOWN BUSINESS AREAS	192.723	USE FORM 3
	DISTRIBUTION MAINS AND SERVICES	192.723	USE FORM 3, 4
4.	PRESSURE REGULATING STATIONS	192.739	USE FORM 6
5.	*REGULATOR STATIONS, RECORDING OF PRESSURES	192.741	MAINTAIN AND SAVE ALL RECORDING CHARTS (DATE CHARTS AND FILE IN ORDER BY DATE)
6.	PRESSURE RELIEF VALVES	192.743	USE FORM 6
8.	VALVE MAINTENANCE, DISTRIBUTION LINES	192.747	USE FORM 8, 9
9.	*ODORIZATION OF GAS	192.625	USE FORM 10, 11
10.	CORROSION CONTROL (EXTERNAL)	192.465	USE FORM 14
11.	CORROSION CONTROL (ATMOSPHERIC)	192.481	USE FORM 13
12.	CORROSION CONTROL (EXAMINATION)	192.459	USE FORM 1
13.	*CORROSION CONTROL (RECTIFIERS)	192.465	USE FORM 15
14.	TESTING OF PIPING	192.501 TO 192.517	USE FORM 16

*May not apply to small master meter operators

Form 1

_________________Gas Utility

REPORT OF MAIN AND SERVICE LINE INSPECTION

This form to be completed each time a transmission main or distribution main or service line is uncovered for inspection or other reason, such as making service connection, main extension, replacement, etc.

(if you are not POSITIVE, leave answer blank).

Date: ____________ 19___

1. Location: ____________________

2. Name of Inspector: ____________________

3. Designation of Line: Trans. ______ Dist. ______ Service ______

4. Age: ______ Years Line Size: ______ Inches

5. Maximum Operating Pressure: ____________________

6. Pipe Specification: ____________________

7. Cathodic Protection: Yes____ No ______ Anodes ______ Other ______

8. Coating: Type ______________ Condition ______________

9. External Condition: Smooth ________ Pitted ________ Depth of Pits ________

10. Internal Condition: Smooth ________ Pitted ________ Depth of Pits ________

11. Other Structures in Area Endangering Pipeline: ____________________

____

____

12. Condition of Right-of-Way: ____________________

____

____

13. Corrective Measures Taken If Needed: ____________________

____

14. Number of Anodes Installed: Size ________ Location ________

15. Soil: Kind: Sand ( ) Clay ( ) Loam ( ) Cinders ( ) Refuse ( )

Packing: Loose ( ) Medium ( ) Hard ( )

Moisture Content: Dry ( ) Damp ( ) Wet ( )

Form 2

GAS LEAK AND REPAIR REPORT

Report No. ____________

Receipt of Report:

Date: ____________ Time: ____________ A.M. P.M.

Location of Leak: ______________________________

(address, intersection, etc.)

Reported by: ______________________________

(Name) (Address)

Description of Leak: ______________________________

(inside/outside)

____

Leak detected by: ____ Odor ____ Noise ____ CGI ________ Other

Leak reported by: ____ Public ____ Customer ______ Survey Crew ______ Other

Report Received by: ______________________________

Dispatched

Date: ____________ Time: ____________ A.M. P.M.

Investigation Assigned to: ______________________________

(Name)

Assigned as immediate action required? ______ Yes ______ No

Investigation

Date: ____________ Time: ____________ A.M. P.M.

Investigation by: ____________ Leak Found? ______ YES ______ No.

CGI Used? ______ YES ________ NO Leak Grade: ______ 1 ______ 2 ______ 3

Location of Leak: ______________________________

____

Cause of Leak: ______________________________

Condition Made Safe: Date ____________ Time ____________ A.M. P.M.

Repair Report: Length Exposed ________ feet.

Leak at: Threads ______ Coupling ____ Weld(give type) ______ Valve ______ Other ______

Pipe: Size _____ Steel ____ Plastic ____ C.I. ____ Other ____ Depth ______

Coating: Enamel ____ Wrapped ______ Galv. ______ Other ______

Condition: Excellent _____ Good _____ Fair _____ Poor _____

Soil Conditions: Sand ____ Clay ____ Loan ____ Other (describe) ______

Moisture: Dry ________ Damp ______ Wet ______

Repairs Made ______________________________

____

Repair Coating Type Mastic ____ Hot Applied Tape ________ Other ________

Anodes Installed: How Many ____ Anode Weight ____ Lbs Depth Installed ____ In.

Remarks: ______________________________

Repairs Made by: ______________ Date: ______________

Foreman ______________ Supervisor ______________ Date

Posted BY ____________ DATE ____________

LEESBURG GAS DEPARTMENT Form 3

GAS DISTRIBUTION INSPECTION AND LEAKAGE REPAIR

ADDRESS ______________________ ______________________________

______________________ GRADE OF CASE

______________________ GRADE I ______________________

______________________ GRADE II ______________________

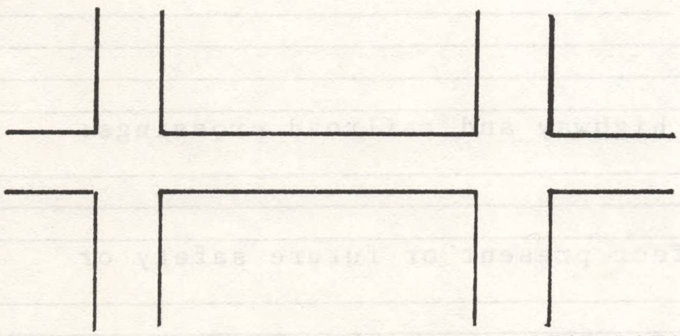
______________________ GRADE III ______________________

SKETCH SHOWING LEAKS LOCATED

METER SET

METER NO. ______________

(if inspected)



LEAK DATA

Detected by		Collecting		Probable Source		C.G.I. TEST	
Mobile Flame Pack		In Building		Main		Gas %	
Flame Pack		Near Building		Service		L.E.L. %	
Visual/Vegetation		In Man Hole		Service Tap		P.P.M.	
Combustible Meter		In Soil		Valve		Negative	
Odor		In Air		Meter Set			
Bar Hole		Other		Tee			

Pressure		Surface		Leak Cause
Low		Lawn		Corrosion
I.P.		Soil		Outside Force
High		Paved		Construction Defect
		Other		Material Failure
				Other

Component & Explanation		Part of System		Pipe & Size Year Installed
Pipe		Main		Steel
Valve		Service		Cast Iron
Fitting		Meter Set		Plastic
Drip		Customer Pipe		Other
Regulator		Other		
Drip Connection				
Other				

Repair Data

Number of Leaks	REMARKS
Bare	
Coated	

GOOD FAIR BAD

Pipe Cond. ______________

Coating Cond. ______________

Repaired ______________

Rechecked

PATROLLING OF DISTRIBUTION SYSTEM

Period Covered: Began ____________________ Ended ____________________

Areas Covered: ____

____

Map References: ____

____

____

Leakage Indications Discovered (describe locations and indications, such as condition of vegetation) ________________________________

____

____

____

Leakage Indications Reported to: ________________________________

Construction Activity Along Areas: ________________________________

____

____

____

Describe any unusual conditions at highway and railroad crossings:

____

____

____

Other factors noted which could affect present or future safety or operation of gas system: ________________________________

____

____

Follow-Up (repairs, maintenance or tests resulting from this inspection): ________________________________

____

____

____

COMMENTS: ____

____

____

____

____

No. of persons in patrol party: ________________________________

Signature of person in charge of patrol party:

____

Date: ________________________________

Form 5

_______________ Gas Utility

____

(If you are not POSITIVE, leave answer blank).

REPORT FOR SCHOOLS AND HOSPITALS

Date: ____________________ 19 ____

Name of Building: ________________________ Town: ____________________

Location: ________________________________ Inspectors: ___________________

Check List:

1. Supply Main: Average Pressure ____________ Location __________________

   Method of Leak Test: ________________________ Results ________________

   ____

2. Service Line: Size ______________ Location _________________________

   Method of Leak Test: ______________________ Results: _______________

   ____

   Entrance Above or Below Ground? _____________ Is Meter Stop Accessible

   and in Good Order? ____

3. Meter: Make ____________________ Size ________ Number ______________

   Location: ____

   Case & Fittings Tested for Leaks? ___________________________________

   Method: ________________________ Results: __________________________

4. Regulators: Make ___________ Size ___________ Number ________________

   Delivery Pressure: ___________ Vented Properly? _________ Diaphragm

   Case Vented to Outside? ___________ Relief Valve Make _______________

   Size ___________ Were Regulator and Fittings Tested for Leaks? _______

   Results: ____

   Indication of Leakage on Meter with Appliances Off? ________________

Signed: ___________________________

Form 6

REGULATOR INSPECTION REPORT

LOCATION ____________ DATE ____________

____

ORIFICE SIZE ____________

MAKE: ____________ TYPE: ____________ SIZE: ____________

PRESSURE RATING: INLET ____________ OUTLET ____________

M.A.O.P. OF SYSTEM TO WHICH IT IS CONNECTED ____________

OPERATING PRESSURE: INLET ____________ OUTLET ____________

LOCK UP PRESSURE ____________

MONITORING REGULATOR OR RELIEF SETTING: ____________

WAS THE REGULATOR STROKED (TO FULLY OPEN)? YES ________ NO ________

GENERAL CONDITION OF STATION

ATMOSPHERIC CORROSION: YES ________ NO ________

SUPPORT PIPING RIGID: YES ________ NO ________

STATION GUARDS: YES ________ NO ________

AREA CLEAN OF WEEDS AND GRASS: YES ________ NO ________

CAPACITY AT INLET AND OUTLET PRESSURE: ____________

CORRECTIONS MADE ____________

REMARKS: ____________

____

SAMPLE

RELIEF VALVE INSPECTION REPORT

OWNER ______________________________ DATE ______________

LOCATION ______________________________

____

MAKE ______________________________

TYPE ______________________________

SIZE ______________________________ Orifice size ______

TYPE OF LOADINGS:

SPRING ______________ PILOT ______________ OTHER ______________

RANGE ______________________________

PRESSURE SETTING ______________________________

CONNECTION PIPE SIZE ______________________________

VENT STACK SIZE ______________________________

CAPACITY ______________________________

CONDITION OF:

RELIEF VALVE ______________________________

RECORDING GUAGE ______________________________

SUPPORT PIPING ______________________________

STATION GUARD ______________________________

GENERAL AREA ______________________________

REPAIRS REQUIRED ______________________________

____

REPAIRS MADE ______________________________

____

REMARKS ______________________________

____

 INSPECTOR ______________________________ (SIGNED)

VALVE LOCATIONS

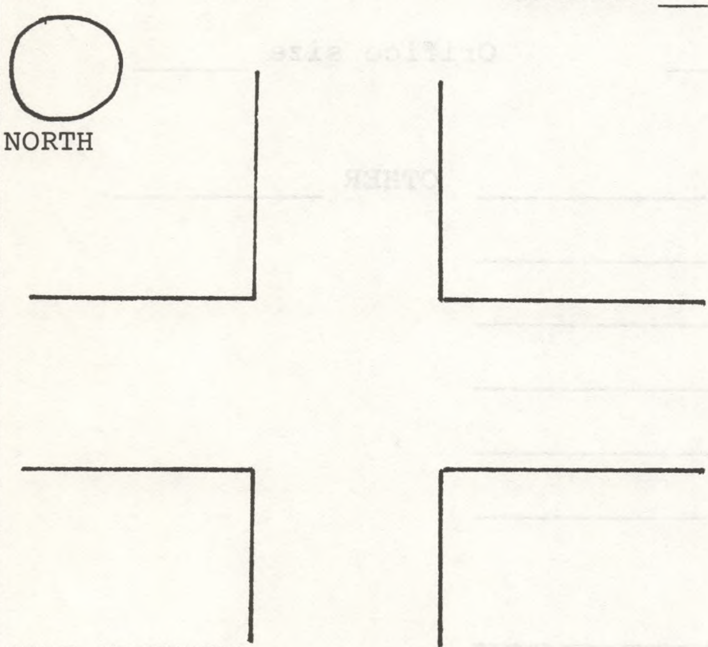
Form 8
SHEET NO. __________

MUNICIPALITY ....LOCATION & REFERENCE BY....DATE......

4" GAS MAIN
SIDEWALK
POWER POLE
GAS VALVE
EDGE OF PAVEMENT
TELEPHONE POLE
MANHOLE
FIRE HYDRANT
TREE
CURB

NOTE: ALL REFERENCE DISTANCES ARE TO NEAREST FACE OF CURB, FIRE HYDRANTS, PAVEMENTS, TELEPHONE POLES, POWER POLES, TREES AND SIDEWALKS AT GROUND LINE.

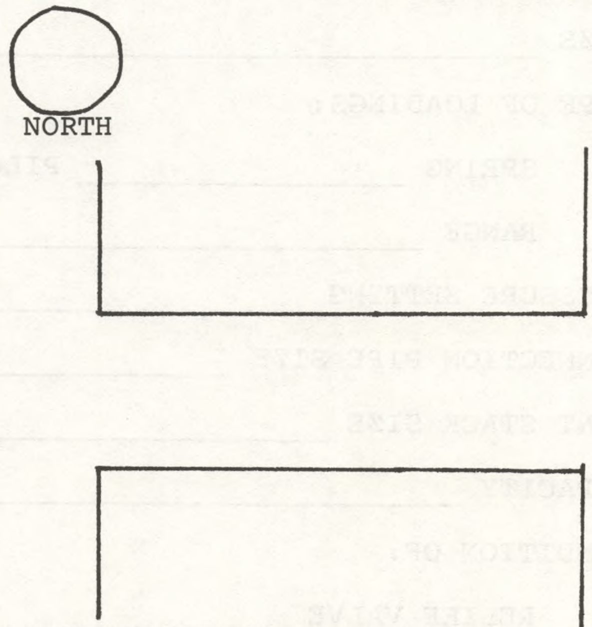
VALVE NO. ____



NORTH

SIZE OF VALVE
TYPE OF STREET SURFACE
DEPTH OF BOX BELOW SURFACE

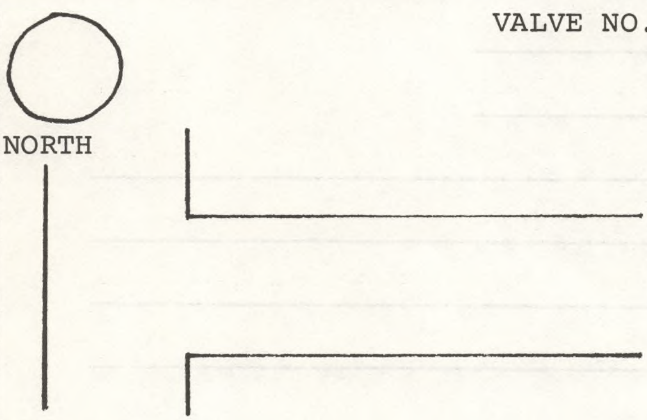
VALVE NO. ____



NORTH

SIZE OF VALVE
TYPE OF STREET SURFACE
DEPTH OF BOX BELOW SURFACE

VALVE NO. ____



NORTH

SIZE OF VALVE
TYPE OF STREET SURFACE
DEPTH OF BOX BELOW SURFACE

VALVE NO. ____

NORTH

SIZE OF VALVE
TYPE OF STREET SURFACE
DEPTH OF BOX BELOW SURFACE

Form 9

______________ Gas Utility

Period ______________, ______________

VALVE INSPECTION REPORT

1. Valve No.: ______ ______ ______ ______
2. Location (Form 106): ______ ______ ______ ______
3. Date Inspected: ______ ______ ______ ______
4. Inspected By: ______ ______ ______ ______

****

1. Valve No.: ______ ______ ______ ______
2. Location (Form 106): ______ ______ ______ ______
3. Date Inspected: ______ ______ ______ ______
4. Inspected By: ______ ______ ______ ______

****

1. Valve No.: ______ ______ ______ ______
2. Location (Form 106): ______ ______ ______ ______
3. Date Inspected: ______ ______ ______ ______
4. Inspected By: ______ ______ ______ ______

****

1. Valve No.: ______ ______ ______ ______
2. Location (Form 106): ______ ______ ______ ______
3. Date Inspected: ______ ______ ______ ______
4. Inspected By: ______ ______ ______ ______

Form 10

MONTHLY ODORIZATION REPORT Month of ....

Period .... to ....

NO...................AREA ....

ODORIZER LOCATION ....

TYPE ODORIZER .... TANK CAPACITY......GAL or LB.

BRAND NAME OF ODORANT USED ....

ODORANT USAGE

1. Odorant in Tank First of Month ....

2. Odorant Added During This Month ....

3. Total Odorant To Account For (Items 1 +2) ....

4. Odorant in Tank End of Month ....

5. Odorant Used During Month (Items 3 -4) ....

6. Gas Delivery This Month ....MMCF.

7. Rate of Odorization in Lbs. or Gal./MMCF

$$\frac{\text{Odorant Used in Lbs./Gal.}}{\text{Gas Delivery in MMCF}} \quad \frac{\text{(Item 5)}}{\text{(Item 6)}}$$ ....Lbs. or Gals./MMCF.

MMCF Million Cubic Foot

Superintendent ______________________________

"SNIFF TEST" and/or "ODOROMETER TEST" Form 11
ODORIZATION CHECK REPORT

Location: ______________________________

Date: ______________________ Time: ______________

Odor Level:
_____ Nil
_____ Barely Detectable
_____ Readily Detectable
_____ Strong

List other odors present: ______________________________

Remarks: (Odorometer Reading) ______________________________

Observed by: ______________

Location: ______________________________

Date: ______________________ Time: ______________

Odor Level:
_____ Nil
_____ Barely Detectable
_____ Readily Detectable
_____ Strong

List other odors present: ______________________________

Remarks: (Odorometer Reading) ______________________________

Observed by: ______________

Location: ______________________________

Date: ______________________ Time: ______________

Odor Level:
_____ Nil
_____ Barely Detectable
_____ Readily Detectable
_____ Strong

List other odors present: ______________________________

Remarks: (Odorometer Reading) ______________________________

Observed by: ______________

Telephonic Report of

Customer Leak

_____________________ Gas Utility

_________________ _________________

Form 12

1. Date: ______________________ 19 ____ Time: ______________ (A.M) (P.M)

2. Filed By: ____

3. Address: ____

4. Account No.: ____________________ Customer Type: ________

5. Nature of Complaint: ____________________________________

____

____

____

Received By:

____

****

DISPOSITION

____

____

____

____

____

____

Date: ________________ 19 ________ Time: ________________ (A.M) (P.M)

____
Title

____
Signed

Form 13

____________________ Gas Utility

________________, ________________________

ATMOSPHERIC CORROSION CONTROL INSPECTION

This form to be completed when above ground piping is inspected for corrosion from atmospheric conditions or corrosive conditions that can not be controlled by cathodic protection. Inspect all exposed piping every three years for atmospheric corrosion. 192.479, 192.481, 192.491

Date: ____________, 19____

1. Location: ____

2. Name of Inspector: ________________________________

3. Designation of Line: Trans. ________ Dist. __________ Service ______

4. Line Size: ____________

5. Area of corrosion: Pipe _______ Meter set _______ Fitting _______

   Regulator __________ Support _______ Vent ______

   Other ________________________________

6. Corrective measures taken: Painted ______ Coated _____ Other ______

   Type of paint or coating used: ______________________

7. If General Painting of exposed Piping is undertaken, list addresses:

CATHODIC PROTECTION SHEET

LOCATION: ____________

TESTS BY: ____________

FOR YEAR: ____________

TEST LOCATION NUMBER	* Indicates Test Station TEST LOCATION	SOIL RESIST. OHMS - cm	CURRENT DRAIN (MILLIAMPHERES) 1 st QTR. MO.___	2 nd QTR. MO.___	3 rd QTR. MO.___	4 th QTR. MO.___	PIPE TO SOIL READING (- VOLTS) 1 st QTR. MO.___	2 nd QTR. MO.___	3 rd QTR. MO.___	4th QTR. MO.___

CORROSION CONTROL

RECTIFIER INSPECTION

Form 15

LINE OPERATOR ____

LOCATION ____

RECTIFIER BRAND ____

SERIAL NO. ____

DATE	SUPPLY VOLTAGE	OUTPUT VOLTS	OUTPUT AMPS	RECTIFIER CONDITION	REMARKS

Form 16

______________________Gas Utility

______________, ____________________________

PIPELINE TEST REPORT

This form must be completed for each section of newly installed section of pipe or service line and on each service line that is disconnected from the main for any reason.

Date ______________, 19___

TYPE OF PIPE ____

SIZE OF PIPE ____

LENGTH OF LINE ____

LOCATION OF LINE ____

____

____

TESTED WITH NITROGEN ___ AIR ___ NATURAL GAS ___ WATER ___ OTHER ___

____

TIME STARTED ____

TIME STOPPED ____

TEST PRESSURE START ____

TEST PRESSURE STOP ____

LINE LOSS ____

REASON FOR LINE LOSS ____

____

____

CORRECTIVE MEASURES TAKEN ____

____

____

Signed By ______________________________
PERSON MAKING TEST

SKETCH LOCATION ON BACK OF THIS SHEET FOR MAPPING PURPOSES
USE ACTUAL MEASUREMENTS AND ADEQUATE REFERENCE POINTS

APPENDIX D

SAMPLE EMERGENCY PLAN

This Appendix has been prepared to provide data essential in an emergency situation. The pipeline safety requirements for emergency plans are contained in 49 CFR 192.615.

No emergency plan can cover all situations. There is no substitution for the sound judgement of the situation by the person or persons involved. In any emergency, the safety of the public must always be given first priority.

Before any emergency you have a responsibility to develop your emergency plan to meet your unique system. In addition, everyone who will have the responsibility of handling an emergency situation should be familiar with the contents of your plan. It is your responsibility, as an operator, to provide this training.

WHAT IS AN EMERGENCY CONDITION?

An emergency condition exists when YOU (OR YOUR REPRESENTATIVE) DETERMINE THAT EXTRAORDINARY PROCEDURES, EQUIPMENT, MANPOWER, AND/OR SUPPLIES MUST BE USED TO PROTECT THE PUBLIC FROM EXISTING OR POTENTIAL HAZARDS.

These hazards may include, but are not limited to facility failures in:

- Underpressure in the system.
- Overpressure in the system.
- Large amounts of escaping gas.
- Fire or explosion near or directly involving a pipeline facility.
- Any leak considered hazardous.
- Danger to major segment(s) of the system.

The hazards also include:

- Natural disasters (floods, tornadoes, hurricanes, earthquakes, etc.)
- Civil disturbances (riots, etc.)

o Load reduction conditions (result in voluntary or mandatory reduction of gas usage)

CONTENTS OF THIS SAMPLE EMERGENCY PLAN

I. Emergency Notification List

II. Map of Key Valve Location

III. Emergency Equipment

IV. Responding to Gas Leak Reports and Interruption of Gas Service

V. A check list for a major emergency

VI. Reporting Requirements (Telephone Report)

VII. Restoration of Gas Service Due to Outage

VIII. Education and Training

IX. Accident Investigation

Complete your plan, then post appropriate charts in a conspicuous place.

I. EMERGENCY NOTIFICATION LIST

OWNER ______________________________

1. OWNER'S OPERATING PERSONNEL:

NAME	ADDRESS	PHONE	EQUIPMENT AVAILABLE

2. OTHERS TO NOTIFY:

AGENCY	LOCATION	PHONE NO.
Police		
Sheriff		
Hwy Patrol		
Fire		
Civil Defense		
Mutual Aid Gas Systems		
Gas Supplier		
Pipeline Contractors		
All Night Service Stations		
Other		

II. MAP OF KEY VALVE LOCATIONS

MAP OF VALVE LOCATIONS AND SCHEMATICS

(DRAW OR ATTACH A MAP HERE THAT SHOWS KEY VALVES, SYSTEM PRESSURES, AND SOURCE OF SUPPLY. KEEP THIS MAP READILY AVAILABLE IN AN EASILY ACCESSIBLE EMERGENCY FILE. BE SURE YOUR EMPLOYEES KNOW ITS CONTENTS AND LOCATION.)

Remember: A gas distribution system is usually a complex network of interconnected mains. They are fed by regulators and have valves throughout for shutting off or diverting the flow of gas. Pressure in the mains may vary from a few pounds to hundreds of pounds. Improper operation of a valve may create a hazardous condition, or make a hazardous condition worse.

Teach your personnel, because ONLY properly authorized personnel should operate valves. Fire, Police, other officials, or other outside individuals ARE NOT AUTHORIZED to operate OR TO INSTRUCT OTHERS, including gas company personnel, to operate valves. (Except "end-use" valve, commonly called the the meter shut-off.)

III. EMERGENCY EQUIPMENT

The operator, or his designate, is responsible for the adequacy, availability and condition of emergency equipment.

(State here the location of such equipment necessary to meet emergency conditions as: valve keys, maps and records, shutoff tools, backhoe, shovels, leak repair equipment, air compressor, and jack hammer.)

Periodic checks of emergency equipment should be taken and records of these inspections should kept on file.

Location and address where additional manpower and equipment and supplies may be obtained: ____________________________

____

____

____

Date ____________________

IV. RESPONDING TO GAS LEAK REPORTS

It is the responsibility of the operator of the gas distribution system to make sure the proper employees are familiar with procedures concerning gas leak calls and reports.

1. The employee receiving a report of a gas leak should get as much of the information as possible to fill out the leak report form properly. (Form 2, Appendix C.) Use common sense: saving human life and property is the first consideration.

2. All reports of leaks on customer premises get priority. LEAKS INSIDE A BUILDING GET TOP PRIORITY.

3. After getting the information, and determining that a hazardous leak exists inside a building, remind the customer of all the following information. (REMEMBER: It is your responsibility to have taught customers in advance.)

   - No one is to turn ON or OFF any electrical switches.
   - No one is to ring door bells or use the phone.
   - Extinquish all open flames. DO NOT LIGHT MATCHES, CIGARETTES, etc.
   - Ventilate building.
   - Turn off gas supply, if feasible.
   - Everyone in the building is to leave the building and go a safe distance (about a block) away. GO ON FOOT—no engines or sparks.

4. Dispatch necessary personnel to the location of the reported leak.

5. DUTIES OF FIRST COMPANY EMPLOYEE ON THE SCENE:

   TAKE EVERY CORRECTIVE ACTION NECESSARY TO PROTECT LIFE AND PROPERTY FROM DANGER (IN THAT ORDER.) IT IS THE RESPONSIBILITY OF THE PERSON IN CHARGE TO:

   - Set up communication.
   - Coordinate the operation.

o Make all decisions concerning emergency valves--isolating areas--and the use of emergency equipment.

o Implement the check list for a major emergency (covered in this plan.)

MINIMUM OPERATOR RESPONSE ACTIONS FOR

6. LEAKS OUTSIDE BUILDING

o Assess danger to public surrounding building, occupants, and property.

o Extinguish all open flames. No smoking.

o If necessary, notify fire and police. (Natural gas master meter operators should also notify gas utility.)

o Block street.

Notify Supervisor or other responsible persons.

o Bar hole next to foundation of building.

o Check neighboring buildings for gas.

o Implement Check List for major emergency - pg. 126

o Repair leak.

o If you are positively sure it is safe, return occupants to buildings.

7. LEAK INSIDE BUILDING

o Evaluate house immediately to determine concentration of gas and source of leak. Evacuate if necessary.

o DO NOT operate any electrical switches.

o DO NOT use phone.

o Shut off gas meter valve.

o Ventilate building.

o Bar hole area especially around foundation. Check water meter and other openings.

o If ground is gas free and if house is gas free, turn on meter valve. CHECK ALL GAS PIPING AND APPLIANCES FOR LEAKS. (Is meter hand turning normally or spinning? Conduct soap bubble test.)

o Implement Check List for major emergency - pg.126

o Repair leak.

o If leak cannot be repaired, notify customer. Turn off meter, lock it, tag it, and leave.

8. GAS BURNING INSIDE BUILDING

o Call fire department.

o Master meter operators should call local gas utility.

9. LP-GAS - SUPPLY TANK

If there is an LP-Gas leak at the supply tank, the following procedures should be followed:

- o If fire is at an appliance, shut gas off at appliance valve.
- o If not possible to shut gas off at appliance valve, shut gas off at meter or curb valve.
- o If fire continues, bar hole area with CGI to locate source of gas.
- o Implement Check List.

- o Approach an LP-Gas leak from upwind and keep out of the cloud.
- o All persons in the probable path of the cloud should be ordered out of the area immediately, ON FOOT. Do not allow motors to operate in the area.
- o Cut all sources of ignition in the probable path of the cloud: pilot lights, electric lights (do not use wall switches—have the utility company cut them off at the pole), telephone, etc.
- o Do not permit anyone to enter the cloud, except in an extreme emergency.
- o Speed up evaporation of liquid by using a water fog nozzle.
- o Have a fire department apparatus stand by in the event of a flash.
- o After evaporation, check low places, pockets, basements, etc., downwind for vapors.
- o Do not restore sources of ignition until complete evaporation has taken place, and the area thoroughly checked.
- o Implement Check List (Pg. 126).

10. INTERRUPTION IN GAS SUPPLY

An interruption to gas supply line could be due to: freezing of the regulators, break in line, sabotage, supplier cut off, or LP-Gas tank out of fuel.

1. Call your supplier (transmission company, natural gas utility, or LP-Gas distributor.)
2. Locate leak. Inform supplier of the location of leak, if possible.

3. Close appropriate valve in your system to isolate the break (if necessary.)

4. Implement Check List.

If peak shaving facilities are available, and IF THE SYSTEM IS NOT ALREADY DEPRESSURED, include plans to go on line to prevent underpressuring of system.

5. It may be necessary to shut off all services and invoke procedures contained under PART VII, Restoration of Gas Service Due to Outage.

V. CHECK LIST (MAJOR EMERGENCY)

____ 1. Has fire department been called?

____ 2. Have persons been evacuated and area blockaded?

____ 3. Has police department been notified?

____ 4. Has repair crew been notified?

____ 5. Has company call list been executed?

____ 6. Has communication been established?

____ 7. Has outside help been requested?

____ 8. Have ambulances been called?

____ 9. Has leak been shut off or brought under control?

____ 10. Has civil defense been notified?

____ 11. Have emergency valves or proper valves to shut down or reroute gas been identified and located?

____ 12. If an area has been cut off from a supply of gas, has the individual service of each customer been cut off?

____ 13. Is the situation under control and has the possibility of recurrence been eliminated?

____ 14. Has surrounding area, including buildings adjacent to and across streets, been probed for the possibility of further leakage?

____ 15. Has proper tag been put on meter?

____ 16. Has telephonic report to the state been made?

____ 17. Has telephonic report to MTB/DOT been made?

____ 18. Has radio station been given instructions (if necessary)?

Date ____________________________

VI. REPORTING REQUIREMENTS

A telephone call must be made to the U.S. Department of Transportation and your state government (if required) for any leak where:

1. There is a release of gas from a pipeline, or of liquified natural gas (LNG) or gas from a LNG facility.

   AND

   There is a death or personal injury requiring hospitalization or there is estimated property damage (including the cost of gas lost, of the operator or others), of $50,000 or more
2. There is an emergency shutdown of a liquified natural gas (LNG) facility
3. There is an event that is significant in the judgement of the operator, even though it was not described in paragraphs (1) or (2) above.

The telephone report to DOT and/or your state should contain:

- o Identity of reporting operator (housing authority, mobile home park name),
- o Name and phone number of individual reporting the incident,
- o The location of the leak (city,county,state, and street address),
- o The time of the leak (date and hour),
- o The number of fatalities and personal injuries, if any,
- o Type and extent of property damage, and
- o Description of the incident

An incident requiring a telephone report must be followed up with a written report unless the report is made by a small operator such as a master meter operator, a condominium or cooperative owner or an owner of rental property such as an apartment building. See Appendix N for written report instructions. The telephonic report, if required, should be made at the earliest practicable moment following discovery (within 2 hours.)

CALL 1-(800)-424-8802 — The U.S. Department of Transportation, National Response Center (NRC) will receive your phone call.

(in Washington, D.C., area call (202) 426-2675

VII. RESTORATION OF GAS SERVICE DUE TO OUTAGE

When the supply of gas has been cut off to an area, no gas should be turned on to the affected area until the individual service to each customer has been turned off.

A house to house operation is mandatory. The individual service of each customer must be turned off, either at the meter or at service valves. If the service valve cannot be located, the gas flow must be shut off in some manner (squeeze off, stopper, install service valve, etc.)

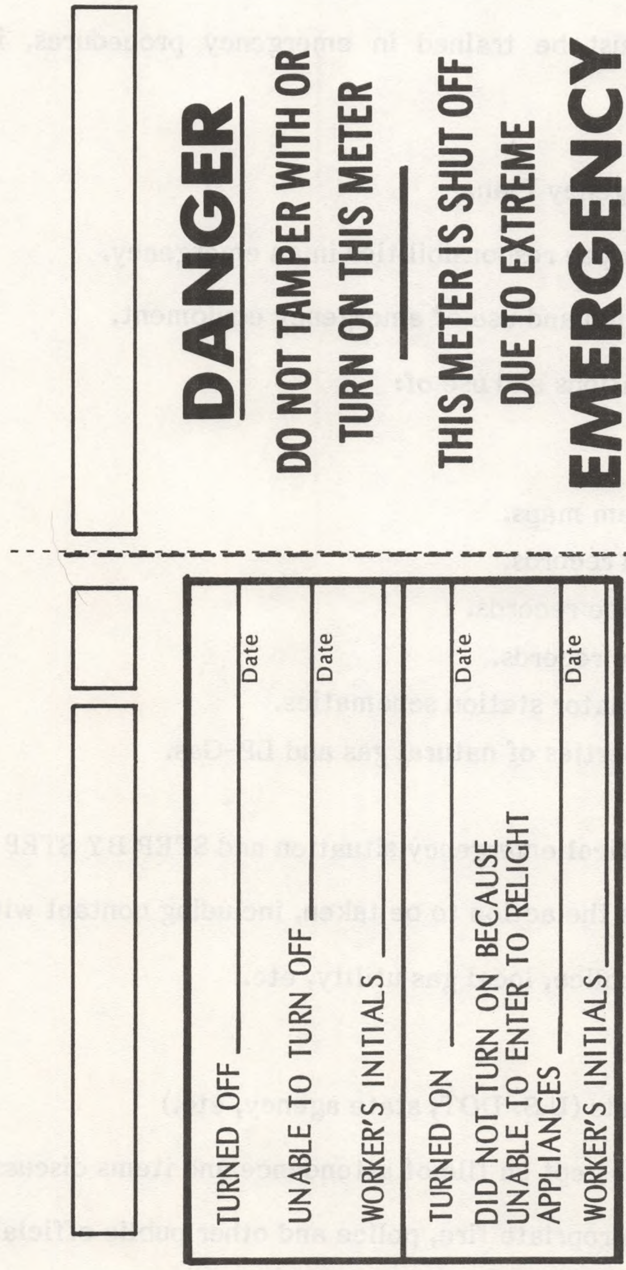
In restoring service to an affected area all gas piping and meters must be purged and appliances relighted. Never turn on gas at meter unless you have access to ALL appliances on the customer piping. In the event a customer is not at home a card must be left in a conspicuous location requesting the customer to call the gas company to arrange for restoration of service. (See Figure D-1 for an example of cards.)

The person in charge is to coordinate this operation and be responsible for same.

A complete record of the incident, with drawings, etc., must be kept on file.

Date ____________________

Figure D-1



DANGER
DO NOT TAMPER WITH OR
TURN ON THIS METER
THIS METER IS SHUT OFF
DUE TO EXTREME
EMERGENCY
TURNED OFF
Date
UNABLE TO TURN OFF
Date
WORKER'S INITIALS
TURNED ON
Date
DID NOT TURN ON BECAUSE
UNABLE TO ENTER TO RELIGHT
APPLIANCES
Date
WORKER'S INITIALS

VIII. EDUCATION AND/OR TRAINING

Employee Training

Periodically employees must be trained in emergency procedures, including but not limited to:

1. Update of Emergency Plan.
2. Review of employee responsibilities in an emergency.
3. Review of location and use of emergency equipment.
4. Review the locations and use of:

    - System maps.
    - Main records.
    - Service records.
    - Valve records.
    - Regulator station schematics.
    - Properties of natural gas and LP-Gas.

5. Take a hypothetical emergency situation and STEP BY STEP review with employees the action to be taken, including contact with public officials, firemen, police, local gas utility, etc.
6. Record keeping.
7. Telephone reports (U.S. DOT, state agency, etc.)
8. Records shall be kept on file of attendance and items discussed.
9. Liaison with appropriate fire, police and other public officials.

Public Education

Each operator must have a continuing education program that enables customers, the public, appropriate governmental organizations, and persons engaged in excavation

related activities, to recognize a gas emergency. Instruct the public in reporting gas odors, leaks and other emergencies to the gas company.

The program material should include, but not be limited to:

- o Information about gas properties.
- o Recognition of gas odors.
- o What to do and not to do when there is a strong gas odor.
- o Notification of the gas company prior to making excavations or excavation related activities.
- o Telephone numbers for customers to report gas leaks or other information during both working and nonworking hours (24 hours/day.)

There are many excellent pamphlets published by state and regional gas associations and by the American Gas Association (AGA) regarding properties of gas and emergency information. This information can be obtained from these organizations at no cost or for a small nominal charge. See Chapter V of this manual for the address and telephone numbers of AGA.

This information may be conveyed to the public by a number of means:

- o Radio and television (if applicable.)
- o Newspaper (such as apartment or condominum newsletter.)
- o Meetings.
- o Bill stuffers.
- o Mailings.
- o Hand-outs.
- o Posted on a bulletin board.

If you have tenants who do not speak English, you must pass this same information to them in the language that they can understand. For examples of information that can be sent to the public, see Figures D-2, D-3, D-4.

A record should be maintained of the public education program and related activities.

Date ______________________

Figure D-2

Stop sneak leaks!

If you ever smell gas, call Washington Gas at 750-1000 promptly!

Natural gas is odorless in its natural state. We add this disagreeable smell to let you know if any gas is escaping.

Gas leakage may occur from faulty appliances, loose connections, service lines inside or outside your home, or from gas mains. Leaks can be dangerous and should be dealt with promptly by experts.

IF YOU EVER SMELL GAS even if you do not use it in your home — take these precautions promptly:

1. Call Washington Gas at 750-1000.
2. If odor is very strong and you are indoors, open windows and doors to ventilate. Go outside. Call us from a neighbor's house.
3. Do not turn any electrical switches on or off.
4. Do not light matches, smoke cigarettes or create any other source of combustion.

However slim the chances of danger, it doesn't pay to take needless risks. At the first sniff of gas, play it safe. Call us.

Natural gas is odorless in its natural state. We add this disagreeable smell to alert you if any gas should escape.

Gas leakage may occur from faulty appliances, loose connections, service lines inside or outside your home, or from gas mains. This can be dangerous and should be dealt with promptly by experts.

If you ever smell gas

even if you do not use it in your own home—take these precautions promptly:

1. Call Washington Gas at 750-1000.
2. If the odor is very strong and you are indoors, open windows and doors to ventilate. Go outside. Call us from a neighbor's house.
3. Do not turn any electrical switches *on or off*.
4. Do not light matches, smoke cigarettes or create any source of combustion.

However slim the chances of danger, it doesn't pay to take needless risks. At the first sniff of gas, play it safe.

Figure D-3

HOW CAN YOU PREVENT GAS EMERGENCIES?

- o Keep all appliances clean, properly vented and serviced regularly.
- o Make sure everyone in your family knows how to operate gas appliances and shut-off valves.
- o Don't use or store gasoline, aerosols or other products with flammable vapors near gas appliances.
- o Don't use an open gas oven for heating your home or drying clothes.
- o If you have a gas log in your fireplace, the damper must be permanently blocked open.
- o Whenever changing your furnace filter be sure to replace your fan compartment door.
- o Never cover fresh air vents that supply air to your gas appliances.
- o Have all gas line alterations and appliance repairs performed by a professional.
- o Before digging in your yard, be sure you know the location of underground gas lines. Call us.
- o Write your fire and police department phone numbers and our emergency service number—in the front of your phone book.

ANYTIME YOU SUSPECT A GAS LEAK OR POTENTIAL GAS EMERGENCY, CALL THE SIERRA PACIFIC POWER COMPANY. WE'RE EXPERTS AT YOUR JOB, AND RESPOND TO EMERGENCY CALLS.

YOUR ROLE IN NATURAL GAS SAFETY, a program presented by the ______ _______ Power Company Speakers Bureau, is available to your organization, group, or school by calling ____.

Figure D-4

WHAT IS NATURAL GAS?

Natural gas is a non-toxic, colorless fuel, about one-third lighter than air. Gas burns, but only when mixed with air in the right proportion and ignited by a spark or flame. In its purified state, gas has no smell. For your protection, the Gas Company adds a harmless, distinctive odor so you can detect and report the slightest gas leak.

HOW SAFE IS NATURAL GAS?

Natural gas has an excellent safety record, but like other forms of energy, it requires a certain amount of caution. Gas emergencies are rare, but they can happen:

- o Whenever gas leaks from a pipe or pipe fitting, there is a possibility of fire or explosion.
- o If leaking gas accumulates in a confined space, it can displace air and cause suffocation.
- o If a gas appliance is not working properly, incomplete combustion can produce carbon monoxide and other toxic gases.
- o A pilot light or gas burner can ignite combustible materials and flammable vapors, such as gasoline, paint thinner or aerosols.

Liaison with public officials and local gas utilities. Establish liaison with fire, police, civil defense, and medical officials with respect to emergency procedures. Master meter operators should develop an emergency plan in coordination with local gas suppliers. Set up communications guidelines.

A RECORD MUST BE KEPT OF ALL MEETINGS, TRAINING SESSIONS, AND OTHER RELATED ACTIVITIES, such as:

- Training sessions on proper procedures to follow during a gas emergency.
- Meetings to learn capabilities, responsibilities, and procedures respecting gas emergencies of each group above.

Information to news media. During an emergency, refer all information requests to the person coordinating emergency actions. Suggest a plan for public announcement such as:

- Calm the situation.
- Do not make reckless comments.
- Tell precisely what the public can do to help.
- Tell specifically what the gas company is doing about it.
- Give the facts to prevent baseless rumors.
- Repeat most encouraging view of situation that facts will permit.
- Do not speculate regarding the situation in absence of facts.

IX. ACCIDENT INVESTIGATION

Each operator must establish procedures for analyzing accidents and failures, and at the least: (49 CFR 192.617)

- Evaluate the situation.
- Protect life and property
- Keep the area safe.
- Conduct a leak survey.
- Conduct pressure tests of piping.
- Do meter and regulator checks.
- Question persons on the scene.

- o Examine burn and debris patterns.
- o Test odorization level.
- o Record meter reading.
- o Record weather conditions.
- o Select samples of the failed facility or equipment for laboratory examination for the purpose of determining the causes of the failure and minimizing the possibility of recurrence.
- o Notify the appropriate insurance company.

APPENDIX E

FEDERAL REQUIREMENTS FOR CORROSION CONTROL

This appendix contains a simplified breakdown of the pipeline safety code corrosion control requirements as they would normally apply to operators of small natural and LP-Gas systems. The complete text of the corrosion control requirements can be found in 49 CFR Part 192, Subpart I.

Procedures and Qualifications

Operators must establish procedures to implement a corrosion control program for their piping system. These procedures should include the design, installation, operation, and maintenance of a cathodic protection system. These procedures must be carried out by, or be under the direction of, a person qualified by experience and training in pipeline corrosion control method (49 CFR 192.453.)

Techniques for Compliance

The following is a list of sources where small operators can find qualified personnel to develop and carry out a corrosion control program:

- o There are many consultants and consulting firms which specialize in the cathodic protection field. Many advertise in gas trade journals. Chapter V of this manual lists a number of these journals, including their addresses and telephone numbers.

- o Another source, especially for master meter operators, is an experienced corrosion engineer or experienced technician working for a local gas utility company. These people may be able to implement the cathodic protection for you, or may be able to refer you to some local qualified corrosion engineer(s).

- o Operators of small municipal systems can contact the transmission company which supplies their gas. Their corrosion engineer, or technician, may be able to supply information as to where to find a local qualified corrosion engineer(s).

- MTB suggests that small operators encourage the associations to which they may belong (such as state and local mobile home associations, municipal associations) to gather and maintain records of consultants, consultant firms, or contractors who are qualified in their specific region.

- The local chapter of the National Association of Corrosion Engineers (NACE) may be able to provide useful information.

- Operators who are unsure whether a consultant is qualified to do corrosion work should ask the consultant to provide a list of other operators for whom he has done work. These operators can be contacted to see if the consultant's work was satisfactory.

Corrosion Control Requirements for Pipelines Installed After July 31, 1971

All buried metallic pipe installed after July 31, 1971, must be properly coated and have a cathodic protection system designed to protect the pipe in its entirety (49 CFR 192.455(a)).

Rule for newly constructed metallic pipelines: each coated pipeline installed must have a cathodic protection system installed and placed in operation in its entirety within one year after completion of construction of the pipeline (49 CFR 192.455(a)). If the operator can demonstrate by tests, investigation, or experience that a corrosive environment does not exist, he is not required to coat and cathodically protect the pipeline. However, no later than 6 months after installation the operator must make tests to prove that no corrosion control measures were necessary. If tests indicate that corrosion control is necessary, cathodically protect (49 CFR 192.455(b)).

MTB recommends that all small operators coat and cathodically protect all new metallic pipe. It is extremely difficult and costly to prove that a noncorrosive environment exists.

Cathodic protection requirements do not apply to electrically isolated, metal alloy fittings in plastic pipelines (a) if the alloyage (such as stainless steel) of the fitting provides corrosion control, and (b) if corrosion pitting of the fitting will not cause leakage.

Corrosion Control Requirements for Gas Distribution Pipelines Installed Before August 1, 1971

For master meter and small municipal gas distribution systems the pipeline safety code requires that bare or coated distribution pipelines, regulating, and measuring stations be cathodically protected in areas of active corrosion (49 CFR 192.457 (c)).

The operator must determine areas of active corrosion by (a) electrical survey, or (b) where electrical survey is impractical, by the study of corrosion and leak history records, or (c) by leak detection surveys.

Active corrosion by federal definition means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety (49 CFR 192.457(c)).

As a guideline for when an operator should consider continuing corrosion to be detrimental to public safety (active corrosion), MTB recommends the following:

- o For master meter operators, all continuing corrosion occurring on metallic pipes (other than cast iron or ductile iron pipes) in a mobile home park or a housing complex, should be considered active and pipes should be cathodically protected, repaired, or replaced.

- o For operators of small municipal gas systems, all continuing corrosion occurring on the distribution system in city limits (within 100 yards of a building intended for human occupancy, regulator stations, and at highway and railroad crossings) should be considered active and pipes should be cathodically, repaired, protected or replaced.

- o MTB recommends that operators of small gas systems and their consultants use these following guidelines in determining where it is impractical to run electrical surveys to find areas of active corrosion:

  (a) Areas of fluctuating stray D.C. currents, such as those caused by telluric currents and electrical railway systems,

(b) Where the pipeline is more than 2 feet in from and generally parallel to the edge of a paved street or within wall to wall pavement areas.

(c) Pipelines in common trench with other metallic structures.

Extreme hardship and expense may render an electrical survey impractical for a given pipeline for conditions other than listed above. The operator, and/or his consultant, must demonstrate with written documentation of test studies, or past experience with electrical surveys for pipelines in a similar environment, the impracticability of the electrical survey.

In areas where electrical surveys cannot be run to determine corrosion, the operator should run leakage surveys on a more frequent basis. (MTB recommends that these surveys be run at a minimum of each calendar year with intervals not exceeding 15 months.)

The electrical surveys conducted to find active corrosion must be run by a person qualified by experience and training in pipeline corrosion control methods. Some basic concepts and practical considerations about corrosion control are discussed in Appendix F.

Coating Requirements

All metallic pipe installed below ground as a new piping system or a replacement system should be coated in its entirety (49 CFR 192.455.) (Form 1, Appendix C)

A discussion of some different types of coatings and handling practices are included in Appendix F.

Examination of Exposed Pipe

Whenever buried pipe is exposed or dug up, the operator is required to examine any exposed portion of the pipe for evidence of corrosion on bare pipe or for deterioration of

the coating on coated pipe. A record of this examination must be maintained. If the coating has deteriorated or the bare pipe has evidence of corrosion, remedial action must be taken (49 CFR 192.459.) (Form 1, Appendix C)

Criteria for Cathodic Protection

Operators must meet one of five criteria listed in Appendix C of 49 CFR Part 192, in order to meet the pipeline safety code for cathodic protection.

The criteria that most small operators will choose to meet will be a (cathodic) voltage of at least -0.85. volts, with reference to a saturated copper-copper sulfate half cell. (Form 14, Appendix C)

In Appendix F some illustrations, basic terms, instruments, and practical considerations regarding protection are discussed.

Monitoring

A piping system which is under cathodic protection must be monitored systematically (49 CFR 192.465.) Tests for effectiveness of cathodic protection must be done at least once each calendar year, at intervals not exceeding 15 months. Records of this monitoring must be maintained. (Form 14, Appendix C)

Short, separately protected service lines or short protected mains may be surveyed on a sampling basis. At least 10 percent of their short sections and services must be checked each year so that all short sections in the system are tested in a 10 year period.

Examples of short, separately protected pipe in a small gas system would be:

- o Steel service lines connected to, but electrically isolated from, cast iron mains.
- o Steel service risers which have cathodic protection provided from an anode attached to a riser which is installed on plastic service lines.

MTB recommends, if you have only a small number of isolated protected sections of pipeline in system, that you include all of these sections in your annual survey.

If you use rectifiers to provide cathodic protection, each rectifier must be inspected six times each calendar year. The intervals must not exceed 2 1/2 months, to insure that the rectifier(s) is operating. Records must be maintained. (Form 15, Appendix C)

Operators must take prompt action to correct any deficiencies indicated by the monitoring.

Electrical Isolation

Pipelines must be electrically isolated from other underground metallic structures (unless electrically interconnected and cathodically protected as a signal unit.) For illustrations of where meter sets are commonly electrically insulated, see Figures 8, 13, and 14 in Appendix F.

Test Points

Each pipeline under cathodic protection must have sufficient test points for electrical measurement to determine the adequacy of cathodic protection (49 CFR 192.469, 192.471.) Test points should be maintained on a cathodic protection system map.

Internal Corrosion Inspection

Whenever a section of pipe is removed from system, the internal surface must be inspected for evidence of corrosion. Remedial steps must be taken if internal corrosion is found. Be sure to keep records of this inspection. (49 CFR 192.475) (Form 1, Appendix C)

Atmospheric Corrosion

Portions of newly installed above ground pipelines must be cleaned and coated or jacketed with a material suitable for the prevention of atmospheric corrosion (49 CFR 192.479.) Above ground pipe, including meter, regulators, and measuring stations, must be inspected for atmospheric corrosion once each calendar year, but with intervals not exceeding 3 years. Remedial action must be taken if atmospheric corrosion is found (49 CFR 192.481.) (Form 13, Appendix C)

Remedial Measures

All steel pipe used to replace an existing pipe must be coated and cathodically protected. Each segment of pipe which must be repaired because of corrosion leak must be cathodically protected (49 CFR 192.483.)

General Graphitization

Definition of graphitization: Cast iron is a metallurgical combination of iron and carbon (graphite.) During graphitization the cast iron corrodes or rusts out leaving a brittle sponge-like structure of graphite flakes. There may be no outward appearance of damage but in the affected area the pipe becomes brittle. For example, a completely graphitized buried cast iron pipe may hold gas under pressure but will fracture under a minor impact such as being hit by a workman's shovel.

Each segment of cast iron or ductile iron pipe with general graphitization (to a degree where a fracture or any leakage might result) must be replaced. Localized graphitization (to a degree where leakage may occur) must be repaired (49 CFR 192.489.)

Records

Operators must maintain records or maps of their cathodic protection system. Records of all tests, surveys, or inspections required by the pipeline safety code must be maintained. See Appendix C for samples of recording (49 CFR 192.291.)

APPENDIX F

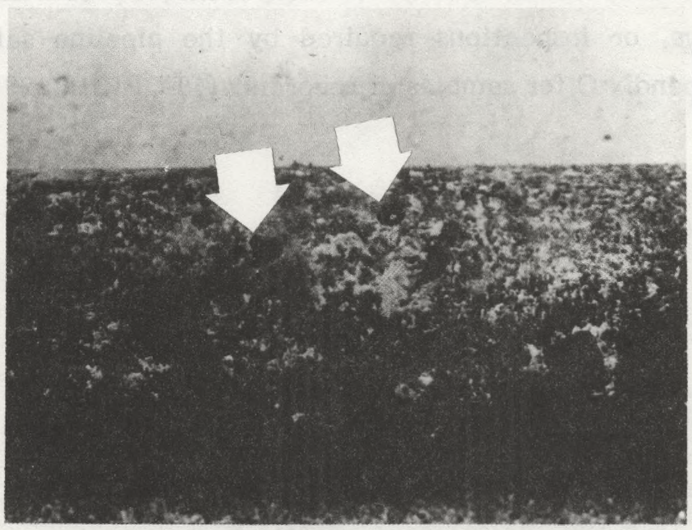
SOME PRINCIPLES AND PRACTICES OF CATHODIC PROTECTION

This appendix gives operators who have little or no experience in the cathodic protection field, some of the general principles and practices of cathodic protection. Common causes of corrosion, types of pipe coatings, and criteria for cathodic protection are typical topics discussed. A check list containing steps which an operator of a small gas system may use in determining his/her needs for cathodic protection is also included. Basic definitions and illustrations are used to clarify the subject. This appendix does not go into great depth. Therefore, reading this appendix alone will not qualify an operator to design and implement cathodic protection for a piping system.

BASIC TERMS

Corrosion is the deterioration of a metal pipe. The corrosion is caused by a reaction that takes place between the metallic pipe and its surroundings. As a result, the pipe deteriorates and may eventually leak. The corrosion can be retarded or stopped with cathodic protection. (See Figure F-1.)

Figure F-1 - Bare Pipe - not under cathodic protection



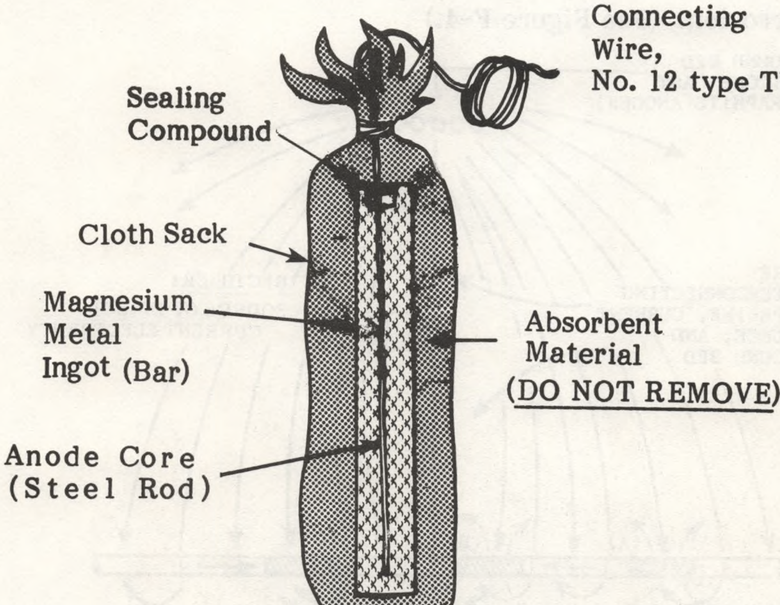
This is an example of bare steel pipe installed for gas service. Note the deep corrosion pits that have formed. Operators should never install bare steel pipe underground.

Operators should use either PE pipe manufactured according to ASTM D2513 or coated steel pipe as new or replacement pipe. If steel pipe is installed, that pipe must be coated and cathodically protected.

Cathodic protection is a procedure by which an underground metallic pipe is protected against corrosion. A direct current is impressed onto the pipe by means of either a sacrificial anode or a rectifier. Pipe will not corrode where sufficient current flows onto the pipe.

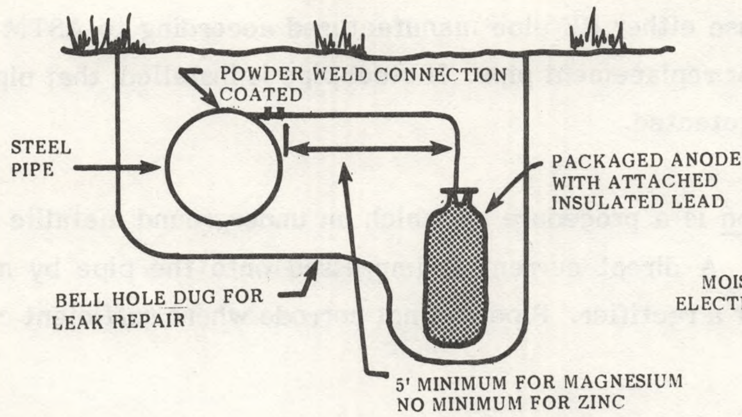
Anode (sacrificial) is an assembly consisting of a bag usually containing a magnesium or zinc ingot and other chemicals which is connected by wire to an underground metal piping system. It serves essentially as a battery which impresses a direct current on the piping system to retard corrosion. (See Figure F-2.)

Figure F-2 - Typical Magnesium (Mg) Anode



Sacrificial protection means the reduction or prevention of corrosion of a metal (usually steel in a gas system) in an electrolyte (soil) by galvanically coupling the metal (steel) to a more anodic metal (magnesium or zinc.) (See Figure F-3.) The magnesium or zinc will sacrifice itself (corrode) and prevent the steel pipe from corroding.

Figure F-3

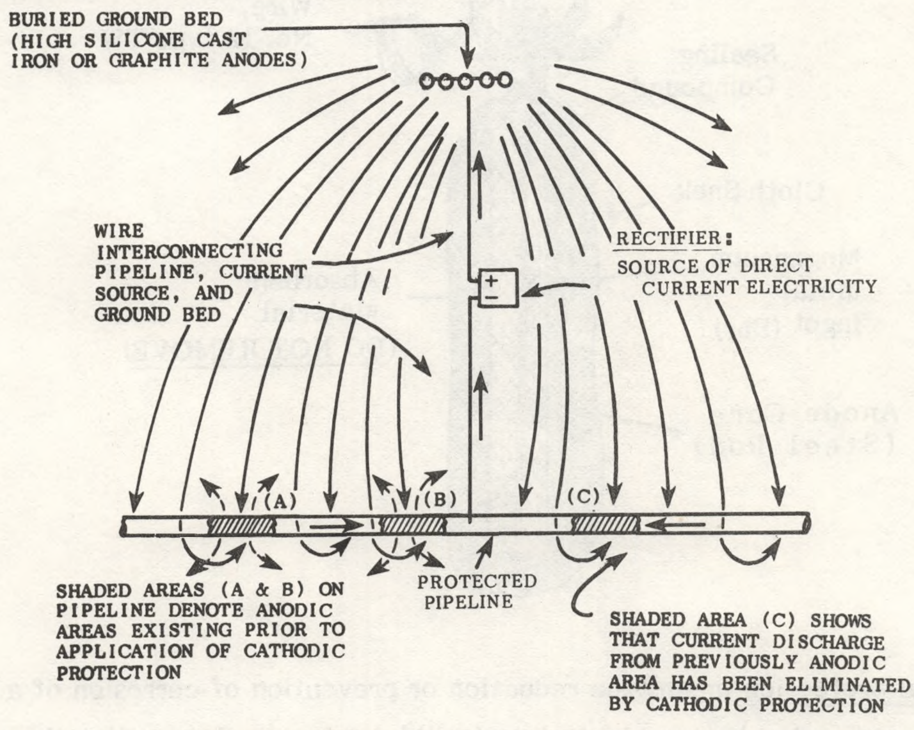


SINGLE PACKAGED ANODE INSTALLATION

Zinc and magnesium are more anodic than steel. Therefore, they will corrode, and provide cathodic protection for the steel pipe to which it is connected.

Rectifier is an electrical device which changes alternating current (A.C.) into direct current (D.C.). This current is then impressed on an underground metallic piping system to protect it against corrosion. (See Figure F-4.)

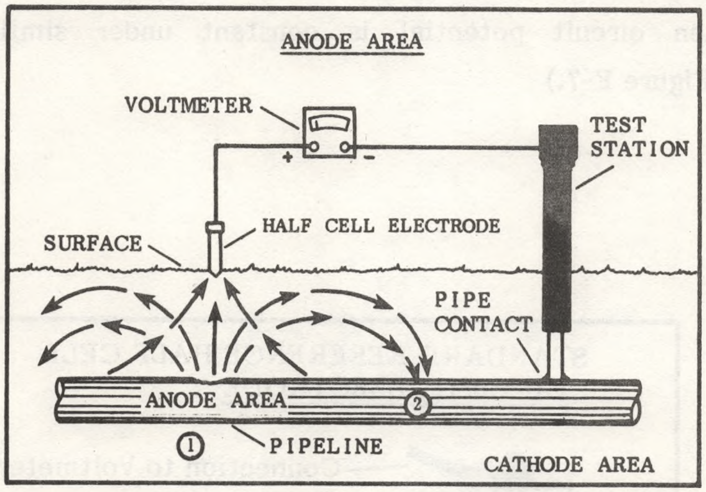
Figure F-4



This illustrates how cathodic protection can be achieved by use of a rectifier. Make certain the negative terminal of the rectifier is connected to the pipe. Note: If you do the reverse (positive terminal to pipe), you will corrode the pipe—FAST.

Potential means the difference in voltage between two points of measurement. (See Figure F-5.)

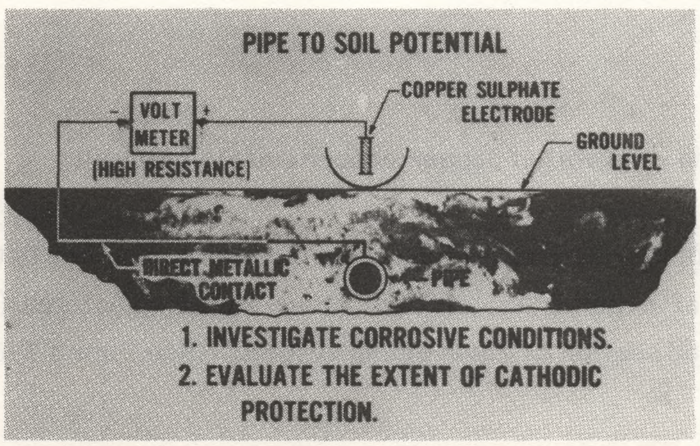
Figure F-5



The voltage potential in this case is the difference between points 1 and 2. Therefore, the current flow is from the anodic area (1) of the pipe to the cathodic area (2). The half cell is a copper-copper sulfate electrode (Cu-$CuSO_4$)

Pipe-to-soil potential means the potential difference between a buried metallic structure of piping system and the soil surface. The difference is measured with a half cell reference electrode (see definition of reference electrode which follows) in contact with the soil. (See Figure F-6.)

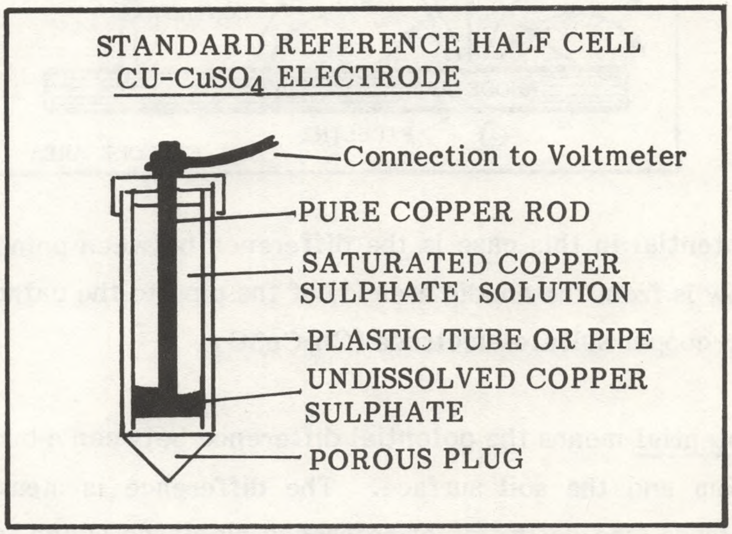
Figure F-6



If the volt meter shown reads at least -0.85 volts, the operator can usually consider that the steel pipe has cathodic protection. Note: Be sure to take into consideration the voltage (IR) drop which is the difference between the voltage at the top of the pipe and the voltage at the surface of the earth.

Reference electrode means a device which usually has copper immersed in copper sulfate solution. The open circuit potential is constant under similar conditions of measurement. (See Figure F-7.)

Figure F-7

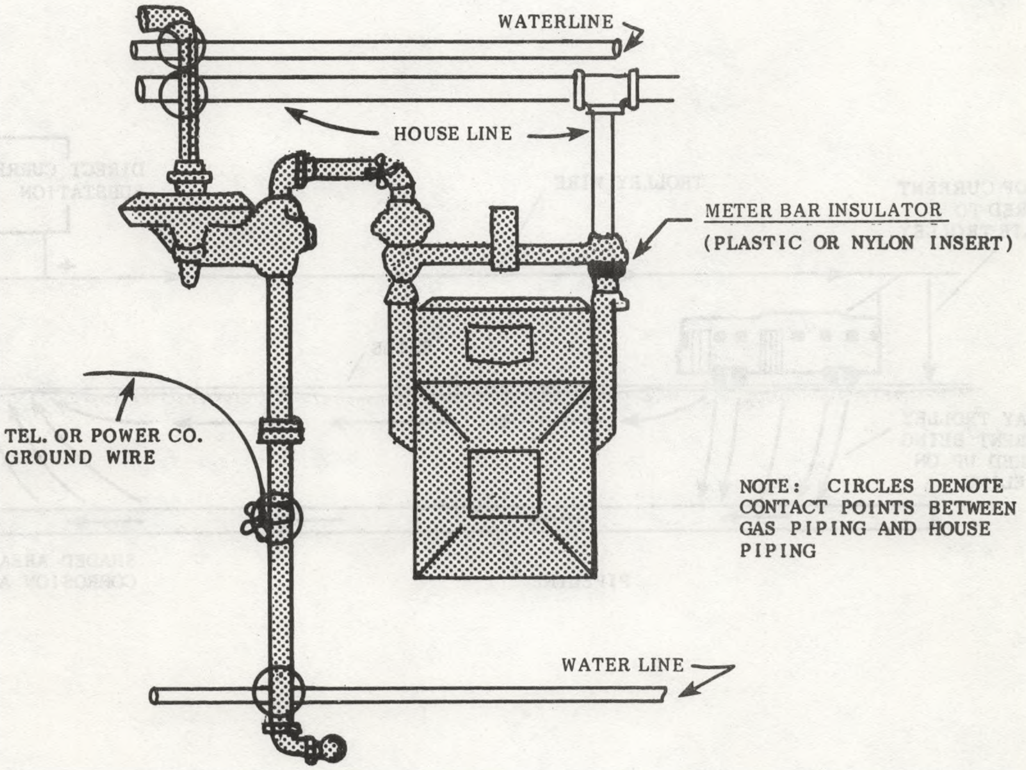


Reference Electrode - Saturated copper-copper sulfate half cell.

Short or corrosion fault means an accidental or incidental contact between a cathodically protected section of a piping system and other metal structures (water pipes, buried tanks, or unprotected section of a gas piping system.) (See Figure F-8.)

Figure F-8 - Typical Meter Installation Accidental Contacts

(Meter Insulator Shorted Out by House Piping, etc.)



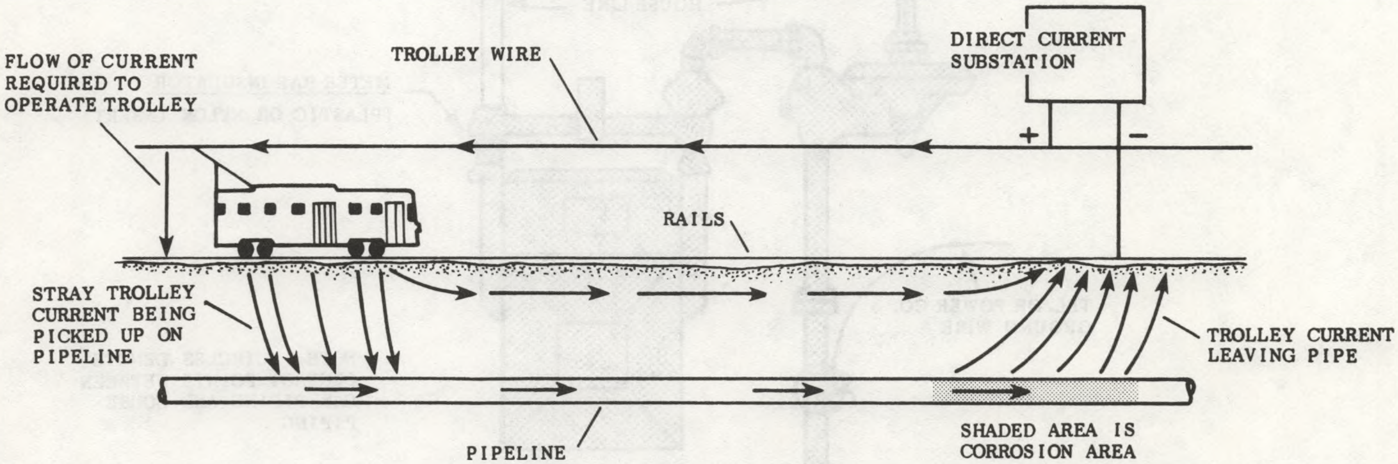
Shaded piping shows company piping from service entry to meter insulator at location shown on sketch above. Unshaded areas show house piping, BX cables, etc.

The locations that are circled are typical points at which the company piping (shaded) can come in metallic contact with house piping. This causes shorting out or "by-passing" the meter insulator.

The only way to clear these contacts permanently is to move the piping that is in contact. The use of wedges, etc., to separate the piping <u>is not acceptable</u>. If you cannot move the piping, install a new insulator between the accidental contact and the service entry.

Stray current means current flowing through paths other than the intended circuit. (See Figure F-9.)

Figure F-9



This drawing illustrates an example of stray D.C. current getting onto a pipeline from an outside source. This can cause severe corrosion in the area where the current eventually leaves the pipe. Expert help is needed to correct this type of problem.

Stray current corrosion means metal destruction or deterioration caused primarily by stray D.C. current in the soil around a pipeline.

Galvanic series is a list of metals and alloys arranged according to their relative potentials in a given environment.

Galvanic corrosion occurs when any two of the metals in Table 1 (following) are connected in an electrolyte (soil.) This galvanic corrosion is caused by the difference in potentials of the two metals.

Table 1

METAL	Potentials VOLTS*	
Commercially pure magnesium	-1.75	Anodic
Magnesium alloy (6% Al, 3% Zn 0.15% Mn)	-1.6	
Zinc	-1.1	
Aluminum alloy (5% zinc)	-1.05	
Commercially pure aluminum	-0.8	
Mild steel (clean and shiny)	-0.5 to -0.8	
Mild steel (rusted)	-0.2 to -0.5	
Cast iron (not graphitized)	-0.5	
Lead	-0.5	
Mild steel in concrete	-0.2	
Copper, brass, bronze	-0.2	
High silicon cast iron	-0.2	
Mill scale on steel	-0.2	
Carbon, graphite, coke	+0.3	Cathodic

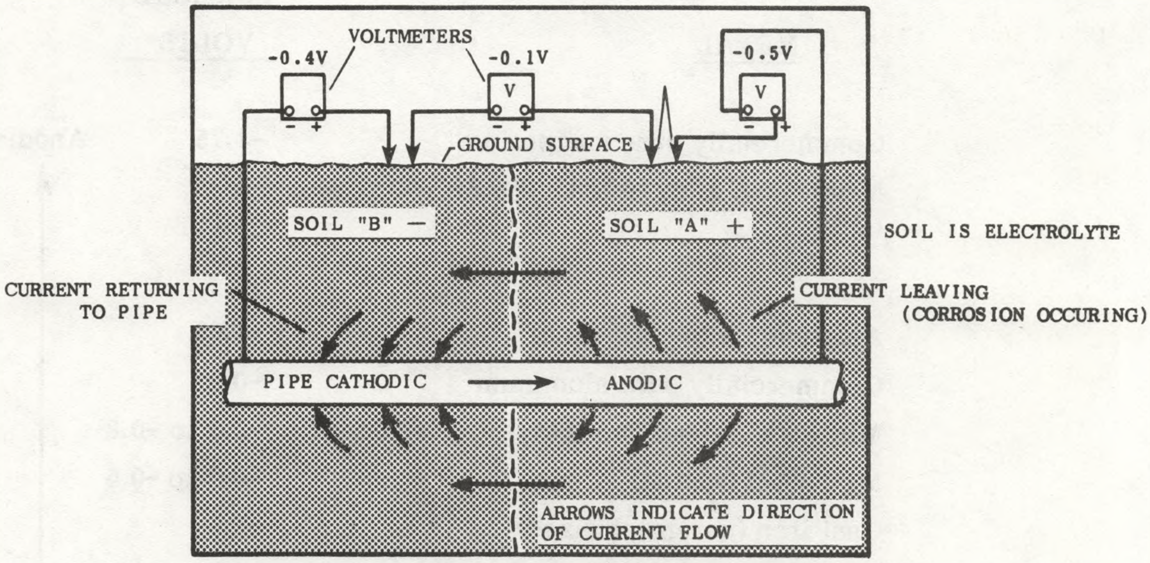
*Typical potential normally observed in natural soils and water, measured with respect to copper sulfate reference electrode.

When connected together in an electrolyte, any metal in the table will be anodic (corrode relative to) any metal below it. (That is, anode sacrifices itself to protect the metal (pipe) lower in the table.)

FUNDAMENTAL CORROSION THEORY

In order for corrosion to occur there must be four elements: electrolyte, anode, cathode, and a return circuit. A metal will corrode at the point where current leaves the structure. (See Figure F-10.)

Figure F-10



CORROSION FROM DISSIMILAR SOILS

A corrosion cell may be summed up as follows:

- Current flows through the electrolyte from the anode to the cathode. It returns to the anode through the return circuit.

- Corrosion occurs wherever current leaves the metal (pipe, fitting, etc.) and enters the soil (electrolyte.) The point where current leaves is called anodic. Corrosion, therefore, occurs in the anodic area.

- Current is picked up at the cathode. No corrosion occurs here. The cathode is protected against corrosion. Polarization (hydrogen film buildup) occurs at the cathode. When the film of hydrogen remains on the cathode surface, it acts as an insulator and reduces the corrosion current flow.

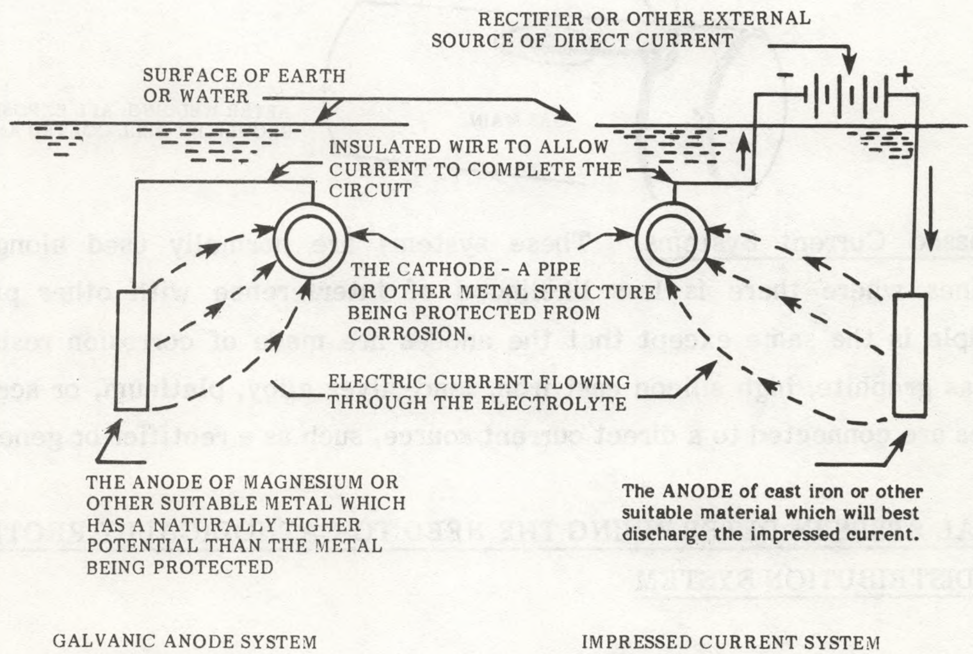
- The flow of current is caused by a potential (voltage) difference between the anode and the cathode.

TYPES OF CATHODIC PROTECTION

There are two basic methods of cathodic protection: the galvanic anode system and the impressed current system.

Galvanic anodes are commonly used to provide cathodic protection on gas distribution systems. Impressed current systems are normally used for transmission lines. However, if properly designed, impressed current can be used on distribution system. (See Figure F-11.)

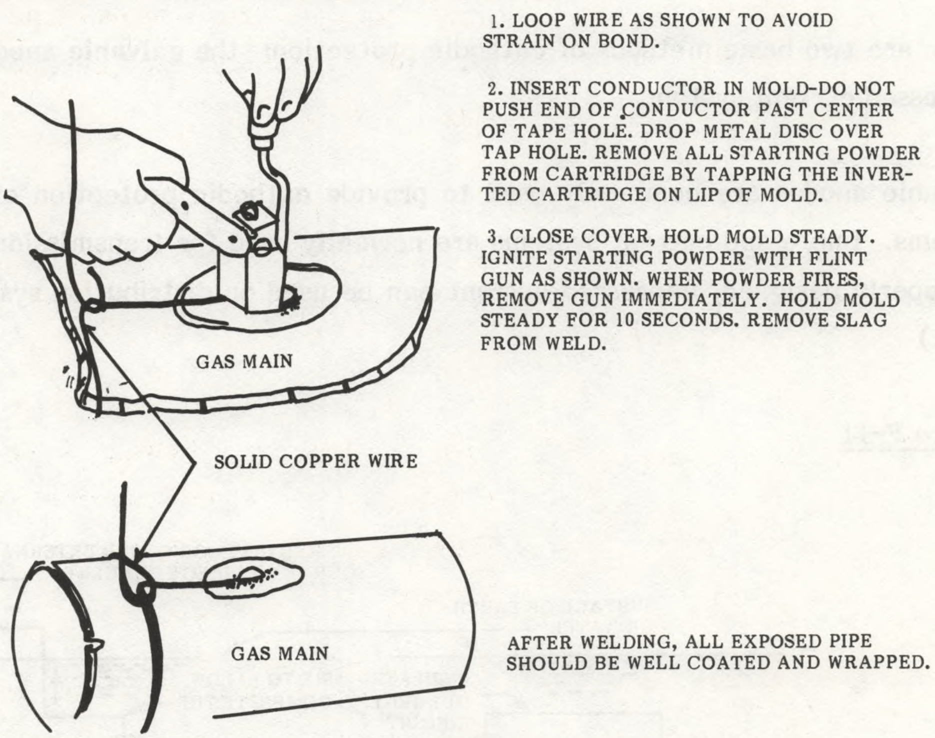
Figure F-11



Any current, whether galvanic or stray, that leaves the pipeline causes corrosion. In general, corrosion control is obtained as follows:

Galvanic Anodes System. Anodes are "sized" to meet current requirements of the resistivity of the environment (soil.) Anodes are made of materials such as magnesium, zinc, or aluminum. They are usually installed near the pipe and connected to the pipe with an insulated conductor. They are sacrificed (corroded) instead of the pipe. (See Figures F-3, F-11, and F-12.)

Figure F-12 - Typical procedure for installing a Mg Anode



Impressed Current Systems. These systems are normally used along transmission pipelines where there is less likelihood of interference with other pipelines. The principle is the same except that the anodes are made of corrosion resistant material such as graphite, high silicon cast iron, lead-silver alloy, platinum, or scrap steel. The anodes are connected to a direct current source, such as a rectifier or generator.

INITIAL STEPS IN DETERMINING THE NEED TO CATHODICALLY PROTECT A SMALL GAS DISTRIBUTION SYSTEM

1. Determine type(s) of pipe in system: ___bare steel, ____coated steel, ____cast iron, ___plastic, ___ galvanized steel, ___ductile iron, or ___other.

2. Date gas system was installed:

   ________ Year pipe was installed (steel pipe installed after July 1, 1971, must be cathodically protected in its entirety.)

__________ Who installed pipe. (By contacting the contractor and other operators who had pipe installed by same contractor, operators may be able to obtain valuable information as:

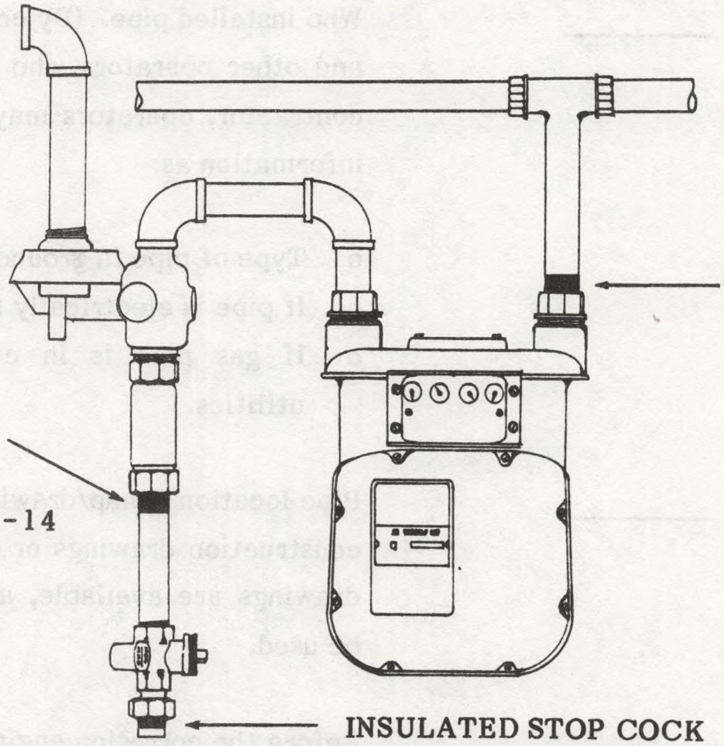
- o Type of pipe in ground.
- o If pipe is electrically isolated.
- o If gas pipe is in common trench with other utilities.

3. __________ Pipe location - map/drawing. Locate old construction drawings or current system maps. If no drawings are available, a metallic pipe locator may be used.

4. __________ Before the corrosion engineer arrives, it is a good idea to make sure that customer meters are electrically insulated. If system has no meter, check to see if gas pipe is electrically insulated from house or mobile home pipe. (See Figure F-13.)

5. __________ Contact an experienced corrosion engineer or consulting firm. (See Appendix E for technics of compliance) Try to complete steps 1 through 4 before you get a consultant.

Figure F-13



Places where a meter installation may be electrically isolated.

Figure F-14

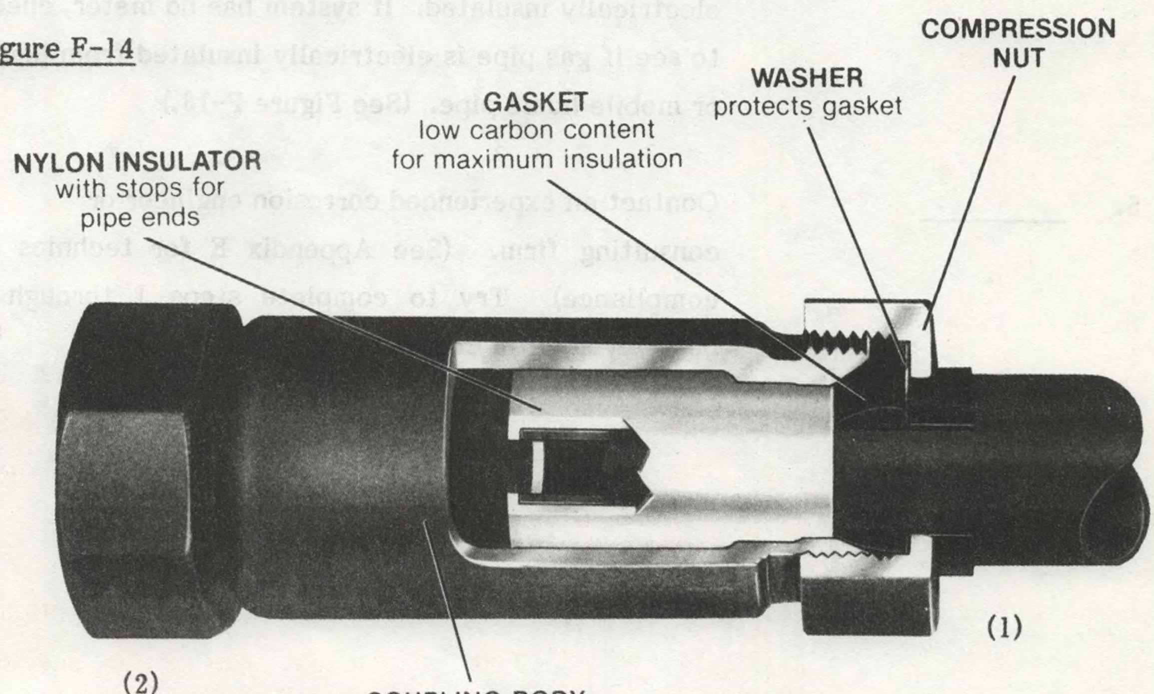
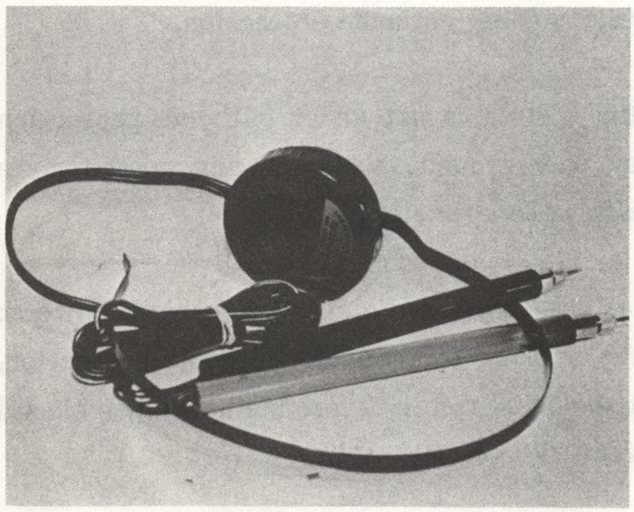


Illustration of an insulated compression coupling used on meter sets to protect against corrosion. Pipe connection by this union will be electrically insulated between the piping located on side one (1) and the piping located on side two (2).

Figure F-15

INSULATION TESTER



This Insulator Tester consists of a magnetic transducer mounted in a single earphone headset with connecting needle point contact probes. It is a "go" or "no go" type tester which operates from low voltage current present on all underground piping systems thus eliminating the necessity of outside power sources or costly instrumentation and complex connections.

By placing the test probes to metallic surface on either side of the insulator a distinct audible tone will be heard if the insulator is performing properly. Absence of audible tone indicates faulty insulator. Insulator effectiveness can be determined quickly using this simple, easy to operate tester.

6. Use of Consultant

A sample method which may be used by a consultant to determine cathodic protection needs is the following:

- o An initial pipe-to-soil reading will be taken to determine whether the system is under cathodic protection.

- o If the system is not under cathodic protection, the consultant should clear underground shorts, or any missed meter shorts. (He/she will probably use a tone test.)

- o After the shorts are cleared, another pipe-to-soil test should be taken. If the system is not under cathodic protection, a current requirement test should be run to determine how much electrical current is needed to protect the system.

- o Additional tests, such as a soil resistivity test, bar hole examination, and other electrical tests, may be needed. The types of tests needed to be run will vary by each specific gas system.

Remember to retain copies of all tests run by the corrosion engineer.

7. Cathodic Protection Design

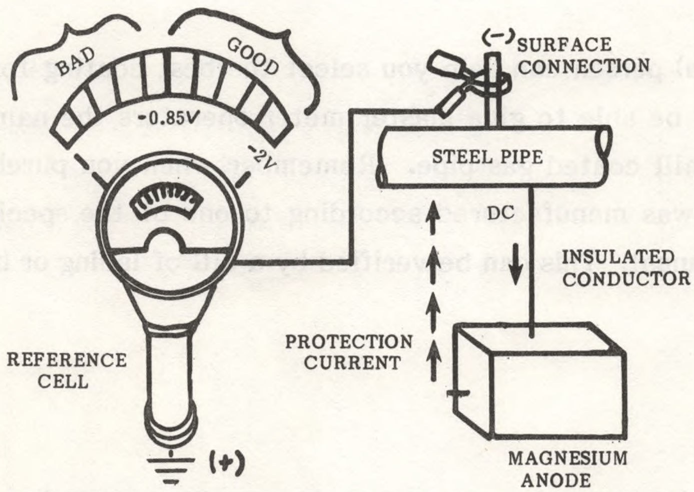
The experienced corrosion engineer or gas consultant, based on the results of testing, will design a cathodic protection system that best suits your piping system.

CRITERIA FOR CATHODIC PROTECTION

There are five criteria listed in Appendix D of Part 192 which qualify as cathodic protection. The operators can meet the requirements of any one of the five to be in compliance with the pipeline safety code. Most systems will be designed to Criteria 1. (Only Criteria 1 is mentioned here.)

Criteria 1: - With the protective current applied, a voltage of at least -0.85 volts measured between the pipeline and a saturated copper-copper sulfate half cell. This measurement is called the pipe-to-soil potential reading. (See Figure F-16)

Figure F-16



This is a pipe-to-soil voltage meter with reference cell attached. This is a simple meter to use and is excellent for simple "go-no-go" type monitoring of a cathodic protection system. If meter reaches at least -0.85 volts, the operator knows that the steel pipe is under cathodic protection. If not, remedial action must be taken promptly. Note: Be sure to take into consideration the voltage (IR) drop which is the difference between the voltage at the top of the pipe and the voltage at the surface of the earth.

COATINGS

There are many different types of coating on the market. The better the coating application, the less amount of electrical current is needed to cathodically protect the pipe.

Mill Coated Pipe

When purchasing steel pipe for underground gas services, operators should purchase mill coated pipe. (i.e., pipe coated during manufacturing process.) Some examples of mill coatings are:

- o Extruded polyethylene or polypropylene plastic coatings.
- o Coal tar coatings.
- o Enamels.
- o Mastics.
- o Epoxy.

A qualified (corrosion) person can help you select the best coating for your system. A local gas utility may be able to give master meter operators the name and location of nearby suppliers of mill coated gas pipe. Remember when you purchase steel pipe to verify that the pipe was manufactured according to one of the specifications listed in Chapter VI of this manual. This can be verified by a bill of lading or by the markings on mill coated pipe.

Patching

Tape material is a good choice for external repair of mill coated pipe. Tape material is also a good coating for both welded and mechanical joints made in the field. One advantage is that these tapes may be applied cold. Some tapes in use today are:

- o PE and PVC tapes with self-adhesive backing applied to a primed pipe surface.
- o Plastic films with butyl rubber backing applied to a primed surface.
- o Plastic films with various bituminous backings.

Consult your pipe supplier before purchasing tapes. Tapes must be compatible with the mill coating on the pipe.

Coating Application Procedures

When repairing and installing metal pipe, be sure to coat bare pipes, fittings, etc. It is absolutely essential that the instructions (supplied by the manufacturer of the coating) are followed precisely. Time and money is wasted if the instructions are not followed.

Some general guidelines for installation of pipe coatings:

- Properly clean pipe surface. (Remove soil, oil, grease, and any moisture.)

- Use careful priming techniques (avoid moisture, follow manufacturer's recommendations.)

- Proper application of coating materials (be sure pipe surface is dry - follow manufacturer's recommendations.) Make sure soil or other foreign material does not get under coating during installation.

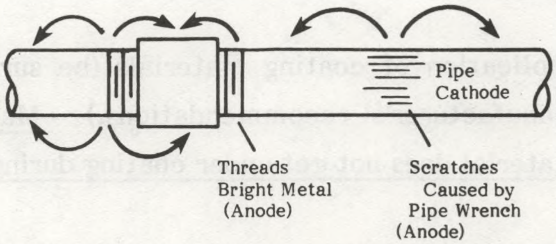
- Only backfill which is free of objects capable of damaging the coating should be allowed to strike the coated pipe directly. Severe coating damage can be caused by careless backfilling operations when rocks and debris strike and break the coating.

COMMON CAUSES OF CORROSION IN GAS PIPING SYSTEMS

Figure F-17

An example of a galvanic corrosion cell being set up. The tenants of this building have "shorted" out this meter by storing metallic objects on meter set. Never allow customers or tenants to store material on a meter installation.

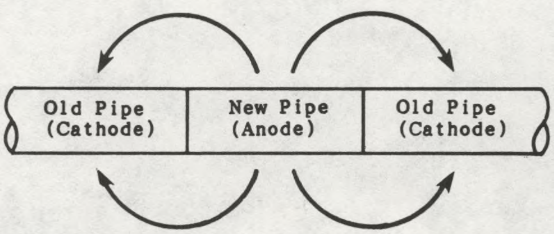
Figure F-18



Corrosion Caused by Dissimilarity of Surface Conditions

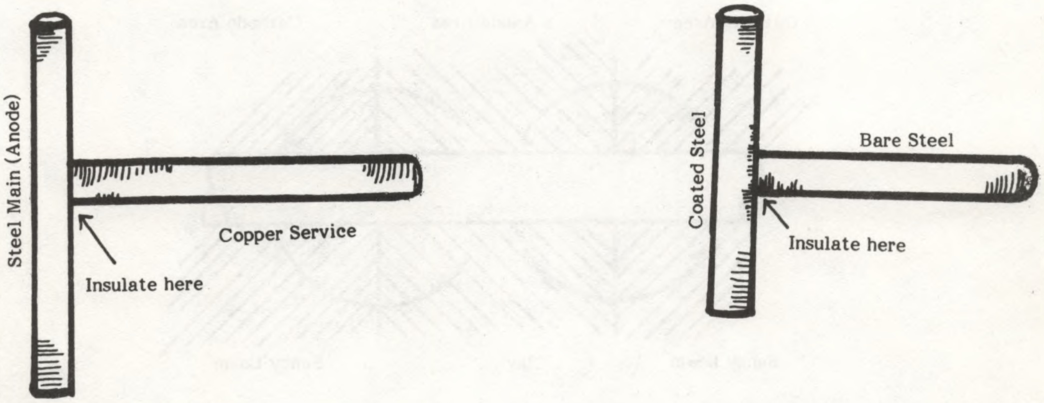
This pipe will corrode at the threads or where it is scratched. Remember to repair all cuts or scratches in the coating before burying the pipe. Always coat and/or wrap pipe at all threaded or weld connections before burying pipe.

Figure F-19 - Galvanic Corrosion



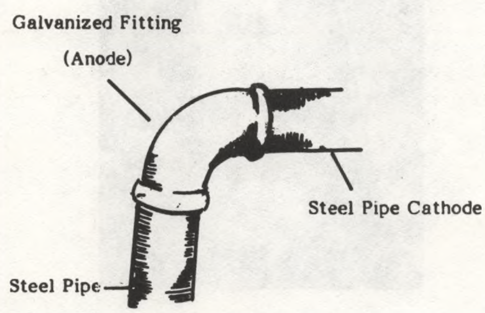
Remember all new steel pipe must be coated and cathodically protected. The new pipe can either be electrically isolated from old pipe, or the new and old pipe must be cathodically protected as a unit.

Figure F-20 - Galvanic Corrosion



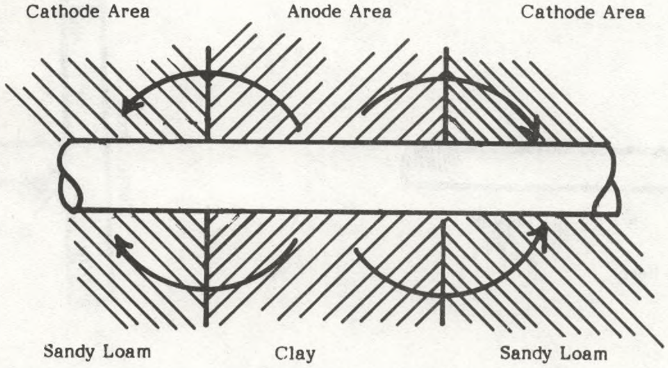
Steel is above copper in the galvanic series in Table 1 of this Appendix. Therefore, steel will be anodic to the copper service. That means, the steel pipe will corrode. The copper service should be electrically isolated from the steel main. Remember, steel and cast iron or ductile iron should not be tied in directly. Steel and cast iron should be electrically isolated. Also, coated steel pipe should be electrically isolated from bare steel pipe.

Figure F-21 - Galvanic Corrosion



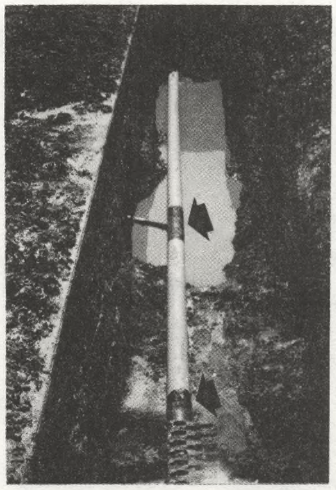
The galvanized elbow will act as an anode to the steel and will corrode. Do not install galvanized pipe or fittings in system, if possible. However, if you use galvanized fittings, you must electrically isolate the fittings.

Figure F-22 - Galvanic Corrosion



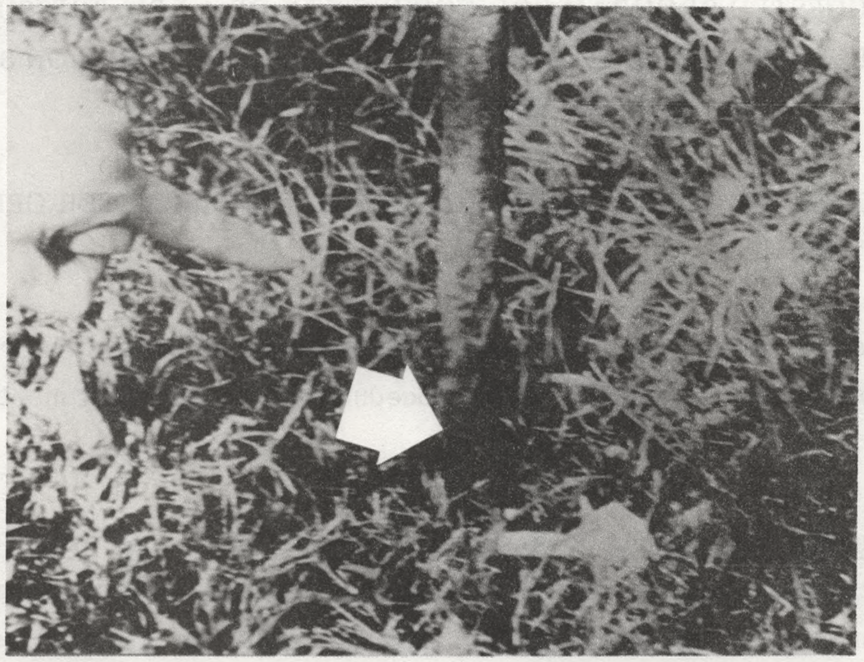
A corrosion cell can be set up when pipe is in contact with dissimilar soils. This problem can be avoided by the installation of a well coated pipe under cathodic protection.

Figure F-23 - Poor Construction Practice



This is an example of a main which was buried without a coating or wrapping at the service connection. Also, you can see (at the bottom of the photo) that the main was not coated. Note that corrosion has occurred at both locations. There are repair clamps at bottom of the photo. This corrosion problem could have been avoided by properly coating and cathodically protecting the pipe.

Figure F-24 - Atmospheric Corrosion



This is an example of atmospheric corrosion at a meter riser. This can be prevented by either jacketing the exposed pipe or by keeping it properly painted. Corrosion is usually more severe at the point the pipe comes out of the ground.

APPENDIX G

SUGGESTED PROGRAM FOR CONVERSION OF A LOW PRESSURE DISTRIBUTION SYSTEM TO A HIGHER PRESSURE DISTRIBUTION SYSTEM (49 CFR, SUBPART K - UPRATING)

THIS APPENDIX WILL NORMALLY NOT APPLY TO MASTER METER OPERATORS OR LPG OPERATORS.

If your gas system requires uprating (conversion of a distribution system from a lower to a higher pressure), then you must develop procedures for doing it that meet the following requirements:

- <u>Pressure increases</u>. Pressure increases must be made gradually, in increments, and at a rate that can be controlled. The pressure must be held constant at the end of each increase while the affected section of the distribution system is checked for leaks.

- <u>Leaks.</u> Each hazardous or potentially hazardous leak detected must be repaired immediately. Other leaks need not be repaired if they are monitored during the pressure increase and do not become potentially hazardous.

- <u>Written plan</u>. A written plan for converting a distribution system from a lower pressure to a higher pressure must be developed and must specify the procedures to be followed before and during the conversion to ensure the safe operation of the system at the increased pressure.

- <u>Records</u>. Records must be maintained for the life of the system and must include, if available, the design specifications. The records should also include the type of work performed, investigations, and tests performed, leaks detected, leaks detected and repaired, replacements, or alterations performed, dates and name of person responsible, and the increase pressure.

The procedures developed for converting a distribution system from a lower pressure to a higher pressure should recognize the type of pipe (steel, cast iron, ductile iron, or plastic) in the system and the operating pressure limitations imposed on the particular type of

pipe fittings or equipment used in the system. The procedures must also provide for a detailed review of the design, operating and maintenance history of the affected section of the system to evaluate its condition, prior to increasing the operating pressure.

The procedures must provide for making a leakage survey (if time elapsed since the last survey exceeds one year), repairing any hazardous leaks found, and monitoring all other leaks during the pressure increase. Make repairs, replacements, or alterations necessary for operation at the increased pressure. This should include the reinforcement or anchoring of offsets, bends, and deadends in piping joined by compression couplings, or bell and spigot joints, if the pipe is exposed at these points during excavation.

The procedures must also include provisions for isolating the section of the distribution system in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure. Monitor the adjacent low pressure segment of pipeline to ensure that is is not being affected by the pressure increase.

Once the above procedures are followed, the increase to a higher pressure must be made in increments that are equal to 10 psig or 25 percent of the total pressure increase, whichever produces the fewer number of increments. However, when the new increased pressure in the affected segment of pipeline is (a) to be higher than the normal utilization pressure, and (b) a service regulator has to be installed and tested for each customer, then there must be at least two approximately equal incremental pressure increases. Your procedures must specify that if the records for cast iron or ductile iron distribution systems are not thorough enough to determine the initial design and laying conditions, the operator must assume (unless the manufacturing process for cast iron pipe is known) that the pipe is pit cast with a bursting tensile strength of 11,000 psi and a modulus of rupture of 31,000 psi. The operator must also assume that when applying the design formulas of ANSI A21.1, the cast iron pipe was supported on blocks with tamped backfill; and that when applying the design formulas of ANSI A21.50, the ductile iron pipe was laid without blocks with tamped backfill.

The procedures must specify that unless the actual maximum cover depth is known, the operator will measure the actual cover in at least three places where it is most likely to be greatest and use the greatest cover measured. Unless the actual nominal wall thickness is known, the operator must determine the wall thickness by cutting and measuring coupons taken from at least three separate pipe lengths in areas where the cover depth is most likely to be the greatest. The average of all measurements taken must be increased by the allowance set forth in the table under 49 CFR 192.557(d)(3) of the minimum federal safety standards.

APPENDIX H

REGULATORS AND RELIEF DEVICES: BASIC CONCEPTS

THIS APPENDIX WILL NORMALLY NOT APPLY TO MASTER METER OPERATORS OR LPG OPERATORS.

In understanding the equipment used to regulate the pressure of natural gas it is helpful to be familiar with some fundamental physical units and concepts. Four are particularly important to regulators. Taken in pairs they are:

PRESSURE and FORCE
FLOW and THROTTLING

PRESSURE

In the gas business the commonly used pressure units are:

psi	pounds per square inch
osi	ounces per square inch
in. w.c.	inches water colum
in. hg	inches mercury column

For convenience, the four units are usually shortened to pounds, ounces, and inches.

It is important to remember that "pounds," "ounces," and "inches" is the short form of expressing pressure units. There really is no such thing as a pound of pressure or an ounce of pressure. They are incomplete terms. Pressure is defined as force per unit area. Pounds and ounces express only the "force" portion of that definition. The unit of "area" is missing. Thus, the complete terminology should be "pounds per square inch" and "ounces per square inch."

When gas is under pressure, it exerts a given force against each unit of exposed area. For example, gas at a pressure of 10 psi pushes with a force of 10 pounds against each square inch of surface exposed to the gas. Gas at a pressure of 5 ounces (remember. . .

ounces per square inch) pushes with a force of 5 ounces against each square inch of surface exposed to the gas.

Such units as pounds or ounces per square foot, per square yard, or other unit area are quite correct. However, for the gas business the unit area used is the square inch. And, to repeat, the complete expressions are pounds per square inch (psi), and ounces per square inch (osi).

Returning to psi, there are some other forms to note as follows:

psia . . . . pounds per square inch absolute
psig . . . . pounds per square inch gauge

The relationship between the two is simple:

psia = psig + atmospheric pressure

Absolute pressure (psia) uses a perfect vacuum as the zero point. A perfect vacuum is 0 psia.

Gauge pressure (psig) uses the actual atmospheric pressure as the zero point. In Miami sea level atmospheric pressure is 14.7 psia. Thus, 0 psig is 14.7 psia in Miami. In Denver (5,280 feet evaluation) atmospheric pressure is 12.1 psia. And 0 psig for Denver is 12.1 psia.

Inches of water column or inches of mercury is often used to express the pressure being delivered to domestic customers. Pressure measurement in inches is usually done with an instrument called a manometer. See Figure H-1. The important relationships to remember are these:

For inches water column
1 psig = 27.71 in w.c.

For inches of mercury column
1 psig = 2.036 in Hg.

Note the physical limitations to pressure measurement with the manometer. The highest pressure that could be measured with a "U" type manometer 5-feet high would be only a little over 2 psig (56 in. w.c.). However, note also that it offers a very precise way of measuring very low pressures.

Mercury offers somewhat more range. A 5-foot high manometer would have a maximum of around 30 psig (61.08 in. hg). It too offers accuracy. In comparison, however, compact dial type gauges are readily and economically available for a wide variety of ranges as high as 1,000 psig and even more.

When expressing pressure in inches, it is necessary to identify the liquid. To put it another way, there really is no such thing as an inch of pressure. Instead, it is inches of some kind of liquid, and in the gas business it is generally water or mercury. Thus, the correct expressions are inches water column (in. w.c., or in. H_20) and inches mercury column (in. hg or Hg). Figure H-1 gives conversion factors for inches water and mercury.

PRESSURE AND FORCE

Force is simply a push or a pull. It is measured in pounds alone.

Note that pounds of pressure is incomplete (it should be pounds per square inch) whereas pounds of force is complete. Thus, it would be "x" pounds of pushing force or pulling force.

Figure H-2 shows the relationship between pressure and force. Note that pressure is used to create a total force. Also note particularly how much force (200 pounds) can be created with only a small amount of pressure (2 psig.) It is all a matter of diaphragm area or piston area. A diaphragm, of course, is simply a low friction, tightly sealed, short stroke piston (just the thing for regulators.)

In Figure H-2 the effective area of the piston or diaphragm is 100 square inches (100 in.^{2}). Applying 2 psig pressure to the 100 in.^{2} area gives an upward pulling force of 200 pounds (100 in.^{2} x 2 lbs/in.^{2} = 200 pounds.)

Note that the pressure above both diaphragm and the piston is atmospheric (0 psig.) The differential pressure across the diaphragm and across the piston is 2 psi (2 psig - 0 psig = 2 psi.)

Note also that the effective diameter of the diaphragm and the piston is only about 11 inches. An 11 inch diaphragm is not very large. This is quite a common size for regulators, particularly on commercial and industrial applications. But an 11 inch diaphragm has a large area (100 $in.^2$). It does not take much pressure (2 psig, for example) to develop quite a large total force (200 pounds.)

FLOW AND THROTTLING

To throttle the flow of a fluid is to allow only a certain amount to flow and hold the remainder back. A faucet provides a good example. How much water is wanted determines how far the faucet is opened. The faucet, (a valve) is a throttling device. Depending on how far it is opened, it allows only a certain amount of water to flow and holds the rest back. It restricts flow to a certain amount.

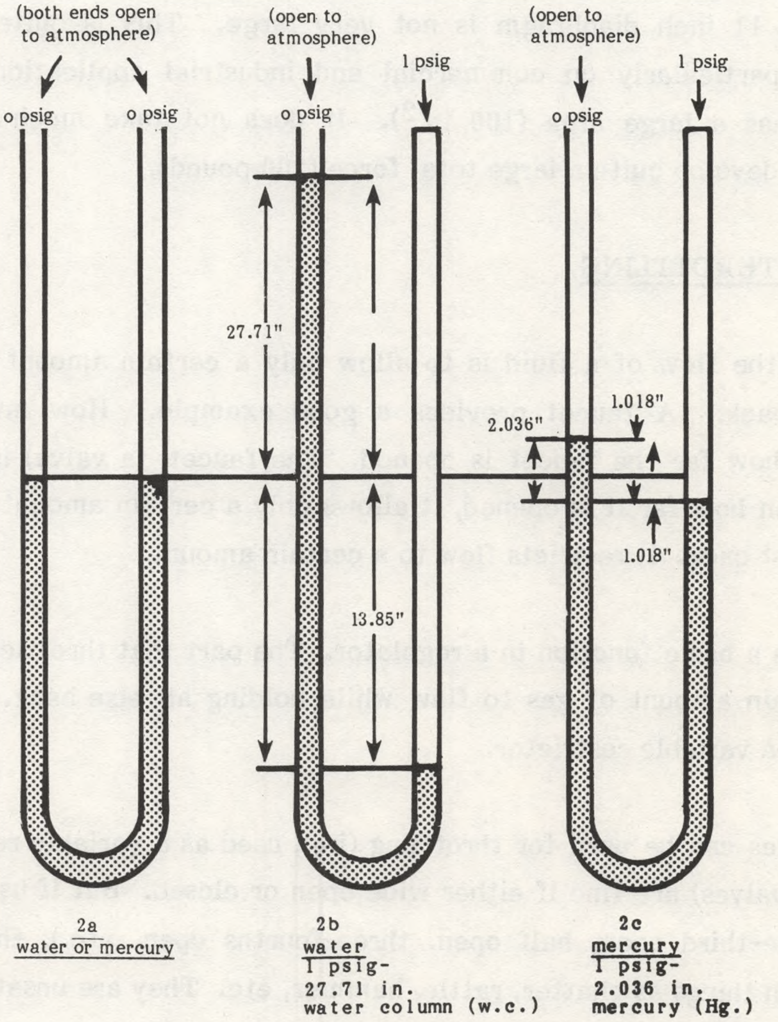
Throttling is a basic function in a regulator. The part that throttles is a valve. It allows only a certain amount of gas to flow while holding all else back. The valve part of a regulator is a variable restrictor.

Not all valves can be used for throttling (i.e., used as a variable restrictor.) Some (like many gate valves) are fine if either wide open or closed. But if used in an intermediate position (one-third open, half open, three-fourths open, etc.), they become unstable. They do such things as chatter, rattle, hammer, etc. They are unsatisfactory.

For a regulator the valve must be mechanically stable from wide open to as small a flow as possible. In addition, it must change flow smoothly as it is opened or closed.

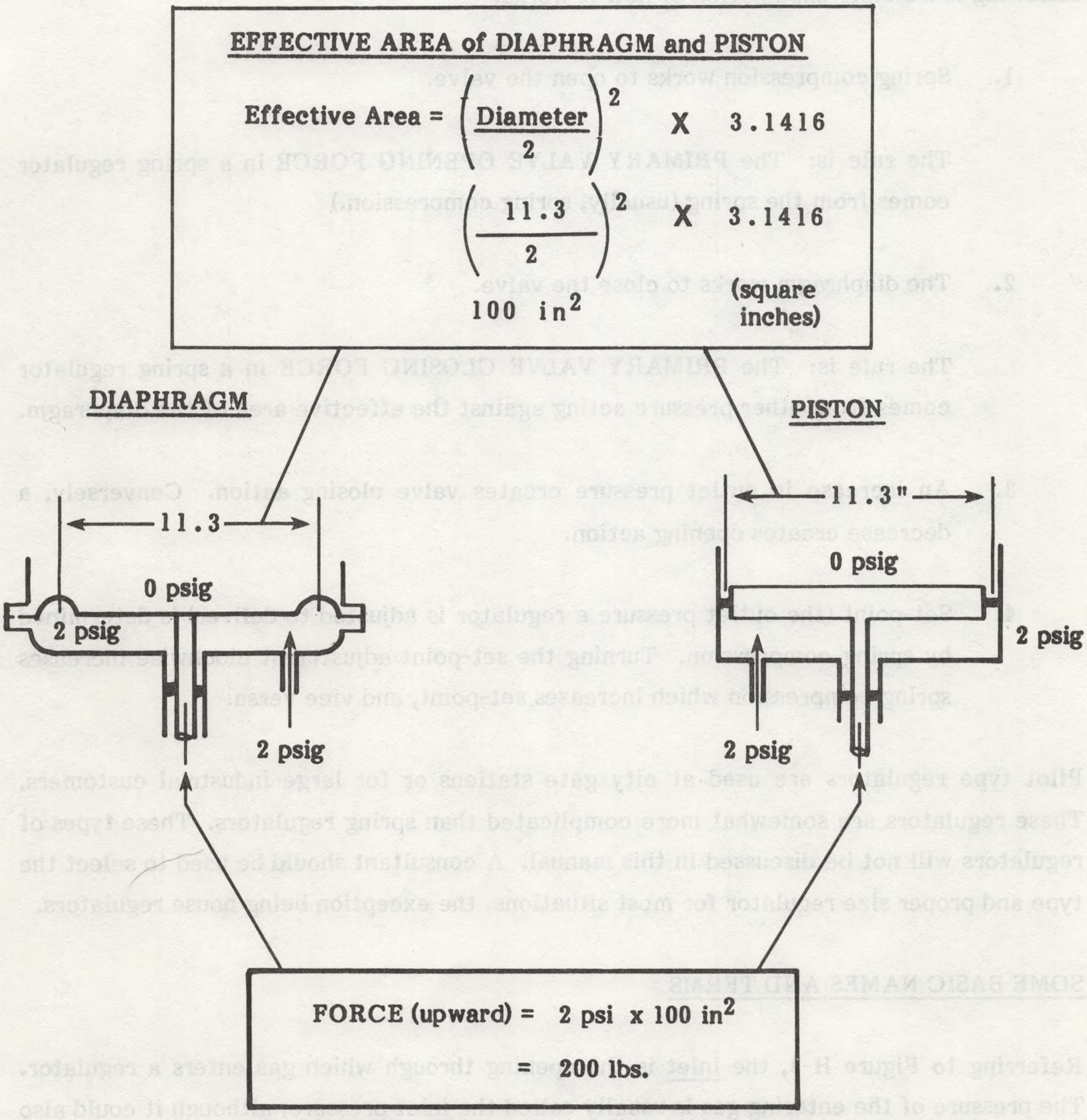
Probably the most widely used valve for regulators is the single-port, unbalanced, globe valve. It comes in a variety of designs which, for the most part, are simple and economical in construction yet provide good throttling. In addition, they stroke freely, have little friction, and have good shut-off (lock-up.)

Figure H-1



U Tube Manometer - Water & Mercury

Figure H-2



Force = Pressure X Area

Figure H-3 shows a simple section of a standard spring regulator. The various parts are labeled. For most small master meter operators this will be the only type of regulator in system. Service regulators are this type of regulator. Referring to Figure H-3, the following is a simple explanation of how it works.

1. Spring compression works to open the valve.

   The rule is: The PRIMARY VALVE OPENING FORCE in a spring regulator comes from the spring (usually, spring compression.)

2. The diaphragm works to close the valve.

   The rule is: The PRIMARY VALVE CLOSING FORCE in a spring regulator comes from other pressure acting against the effective area of the diaphragm.

3. An increase in outlet pressure creates valve closing action. Conversely, a decrease creates opening action.

4. Set-point (the outlet pressure a regulator is adjusted to deliver) is determined by spring compression. Turning the set-point adjustment clockwise increases spring compression which increases set-point, and vice versa.

Pilot type regulators are used at city gate stations or for large industrial customers. These regulators are somewhat more complicated than spring regulators. These types of regulators will not be discussed in this manual. A consultant should be used to select the type and proper size regulator for most situations, the exception being house regulators.

SOME BASIC NAMES AND TERMS

Referring to Figure H-3, the inlet is the opening through which gas enters a regulator. The pressure of the entering gas is usually called the inlet pressure, although it could also be called the upstream or supply pressure.

The outlet is the opening by which gas leaves a regulator. The pressure of the existing gas is usually called outlet pressure, although it could also be called downstream pressure.

In general, the more the inlet pressure exceeds the outlet pressure, the greater the amount of gas that can flow through the regulator, or to put it another way, the greater the capacity of the regulator. The difference between inlet and outlet pressures is sometimes called the differential across the regulator.

Piping on the inlet side is upstream and piping on the outlet side is downstream. As stated previously, a regulator takes higher pressure gas from the supply and reduces it to the pressure required by the load. To do this, something is needed on the regulator to adjust it for the specific pressure required. This adjustment is called the set-point adjustment and on most of today's regulators it is a screw-type device of some kind, usually simply an adjustment screw. Set-point then is the pressure a regulator is adjusted to deliver. It is the pressure required by the load and, in general, is the same as the outlet pressure.

Note the control line. (See Figure H-3A.) It is also called a sensing line, impulse line, equalizing line or static line. The control line along with the sensing point are a vital part of a regulator installation. They must be carefully planned and correctly installed if the regulator is to operate satisfactorily and safely.

Many regulators, particularly smaller ones, do not have the control line externally as shown in Figure H-3A. Instead, it is internal as represented by Figure H-3B. Called internal control, it is built into the inside in some form of open throat construction or venturi tube. However, one way or the other (externally or internally), every regulator has a control line or the equivalent.

Control lines must be adequately protected against breakage. If they are broken, the regulator opens wide and this could result in the full upstream line pressure (that is high) being dumped into the low pressure system you are trying to protect. This can lead to a catastrophic situation.

Next, the vent. While often appearing insignificant, the vent is important to a regulator. Regulators breathe. As the internals move in the work of controlling pressure, a regulator will inhale or exhale through the vent. Therefore, the vent must be adequately protected from obstructions such as dirt, insects, ice, etc. If an obstructed vent prevents a regulator from breathing, there is trouble.

Also, water can get inside a regulator through an improperly positioned and unprotected vent. Water inside a regulator can cause problems. Therefore, vents must be positioned and protected to keep the water out. This is particularly important on outdoor installations.

The last item is the stop valve (Figure H-4). It is a necessary convenience. There may be one or more. A simple installation such as a house usually has only one, the stop cock. A more involved installation such as a regulator station would have several stop valves (inlet stop valve, outlet stop valve, control line valve, by-pass valve, and perhaps others.)

The most important of all is the inlet stop valve. All should be used carefully. The inlet stop valve should be used with extra care, particularly when being opened. Do not open it until you are sure everything is correct and ready. Then open it slowly. Allow the inlet gas to enter slowly, and the pressure to build up slowly.

Stop valves make it possible to put a regulator into service or take it out of service. They make it possible to isolate a regulator for servicing and to conduct certain tests. Correct opening and closing sequences should be adequately understood (these are often specified in gas company standards and procedures.) Usage in case of an emergency should also be understood.

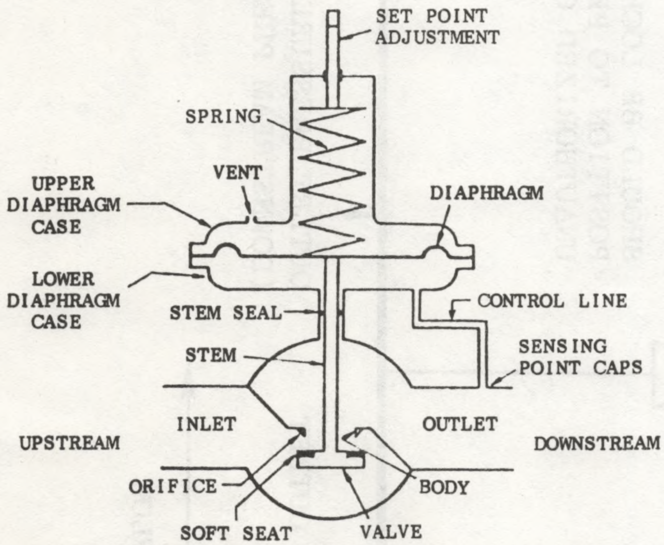
In most cases small operators need to rely on a consultant if a regulator station needs any major work. In the O&M plan, name the person who is responsible for determining when a regulator needs to be serviced. The operator should list the consultant(s) in the O&M plan who is capable of working on regulator stations.

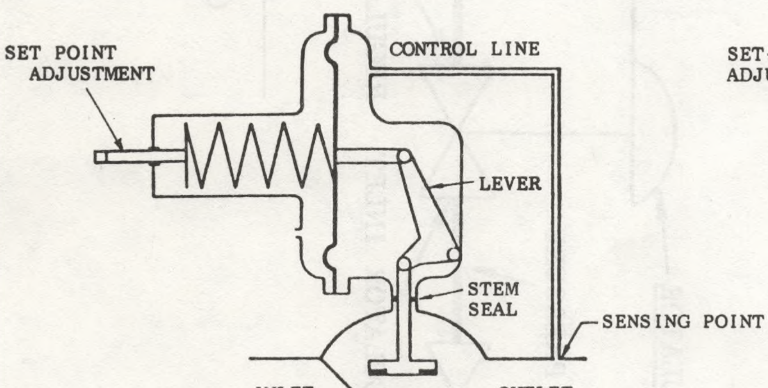
Figure H-3

Typical Single Port Spring Regulators

Figure H-3A: Control Line

STANDARD SPRING REGULATOR
(with Control Line)



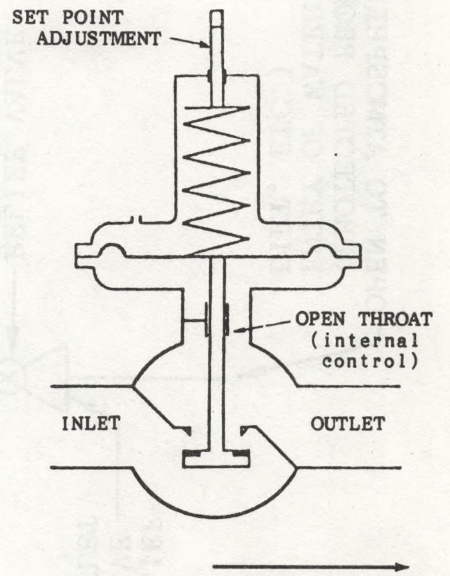


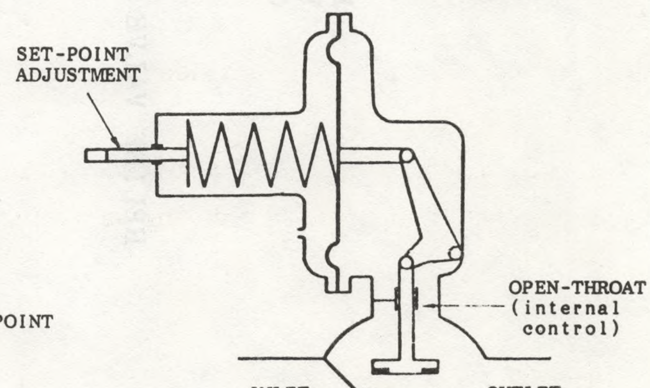
SERVICE REGULATOR
(with control line)

GAS FLOW

Figure H-3B: Internal Control

STANDARD SPRING REGULATOR
(with internal control)



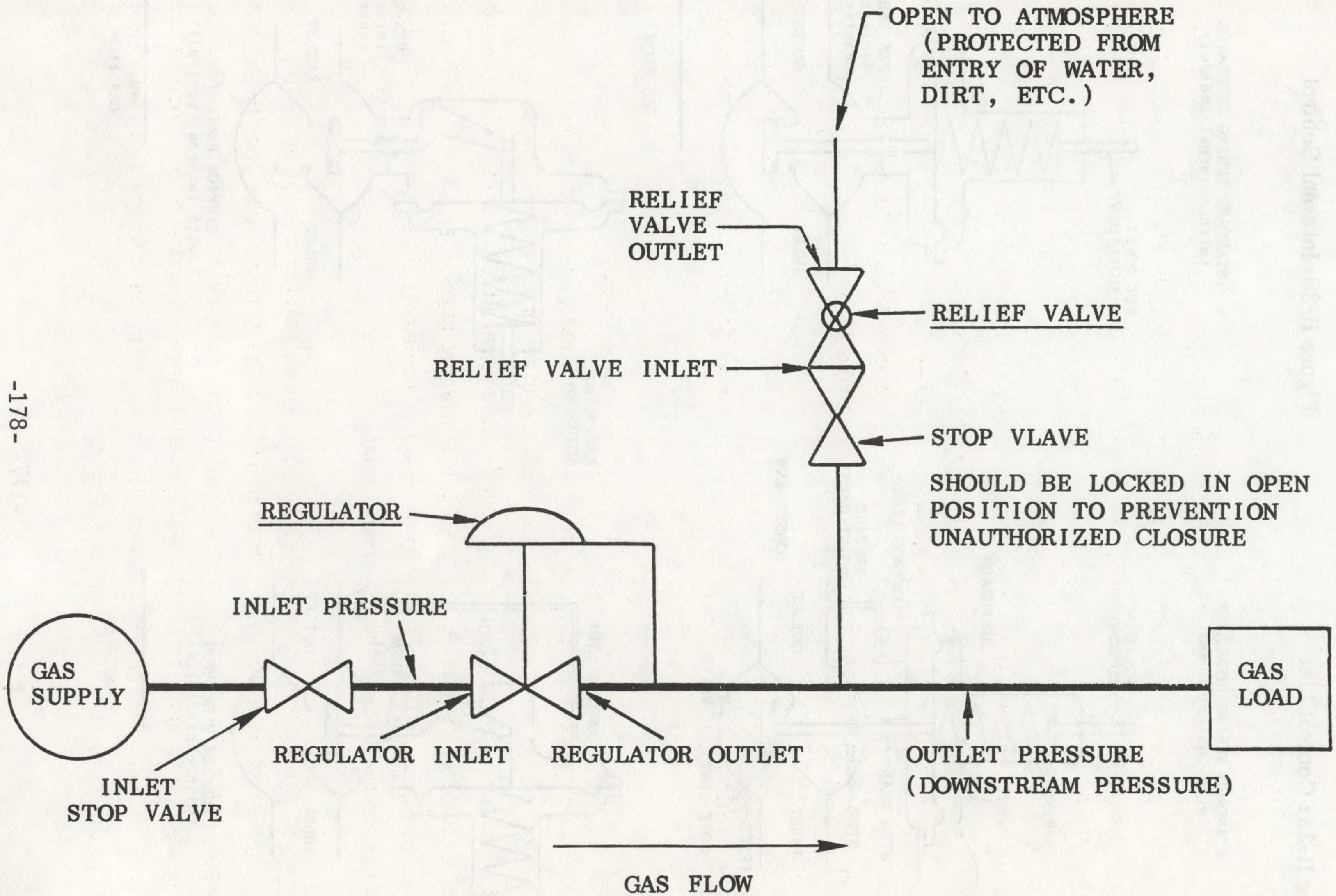


SERVICE REGULATOR
(with internal control)

GAS FLOW

Figure H-4

A Typical Regulator and Relief Valve Installation



OVERPRESSURE PROTECTION

There are three basic methods of providing overpressure protection:

- o Pressure Relief
- o Monitoring
- o Automatic Shutoff

Pressure relief is simply a dumping of excess gas safely into the atmopshere. The excess gas is that which would cause pressure to exceed the safety limit. The relief valve is the most widely used piece of equipment in this category. However, liquid seals and rupture discs may also be used.

In general, relief valves can be classified in a way similar to regulators. There are two basic kinds of operation: self operation and relay operation. These can be subdivided in the same way as regulators. The spring type relief valve is the most widely used. The pilot operated type probably is the next most frequently used, and it offers more precise operation. The pilot operated type becomes more and more frequently used as pressures become higher and capacities greater.

Monitoring involves a standby regulator. The standby prevents pressure from exceeding the safety limit.

The most widely used form of monitoring for the gas business is standby monitoring. It is also called passive monitoring. Such installations consist of two regulators in series, one of which is operating to control pressure while the other is a standby. The standby unit is normally further open than necessary, usually wide open. It takes that positon because it is adjusted for a higher set-point than the operating regulator. If a failure with the operating regulator causes outlet pressure to rise, the monitor takes over at its set-point and holds pressure at that value.

There are two other forms of monitoring which are sometimes used. One simply consists of two stage regulation which, when designed for the purpose, can provide monitoring protection. The other is called override monitoring or working monitoring. With it, the upstream regulator must be pilot operated and have an extra pilot. During normal operation, the set provides two stage regulation. In an overpressure emergency it protects in the same way as standby monitoring.

Automatic shutoff involves a valve that normally remains in the wide open position and allows the gas to flow freely. It is located in series with the regulator, either upstream or downstream, depending on whether it uses a control line or internal control.

If a failure with the regulator results in a rising outlet pressure, the shutoff closes automatically when pressure reaches its set-point. It protects by shutting off the gas and remains closed until manually opened and reset.

In general, there are three primary things to consider in choosing which kind of overpressure protection to use:

1. Continuity of Service .... (does the user, the load, continue to be supplied with gas?)

2. Containment .... (is gas released into the atmosphere or does it remain contained within the gas system?)

3. Alerting .... (is there good notification or warning that an emergency has occurred and that the overpressure protection equipment has gone into operation?)

The following is a comparison of the three basic overpressure protection methods (based on the foregoing three considerations):

Pressure Relief Method

- Continuity of Service. In general, pressure relief valves do not interrupt gas service. They protect, while allowing gas to flow at a safe pressure. Customers continue to get gas.

- Containment. Relief valves do not contain the gas. They protect by dumping the excess gas into atmosphere.

- Alerting. Relief valves are usually good in this respect. For one thing they are noisy, particularly at full or near full blow. In addition, because the gas is odorized, the smell usually attracts attention.

Another indication of overpressure is the rise in outlet pressure above normal, but this is probably the least effective notification of all.

Monitoring

- o Continuity of Service. Monitoring does not interrupt service. Like the relief valve, the monitor protects while allowing gas to continue to flow.

- o Containment. Monitoring contains the gas. It prevents the gas from blowing into the atmosphere. It keeps it inside the piping.

- o Alerting. This is probably the main disadvantage of monitoring. Generally speaking, the only warning or notification is the rise in outlet pressure to monitor set-point. The problem with this is that it usually escapes notice until the regulator station is serviced or inspected.

Automatic Shutoff

- o Continuity of Service. Automatic shutoff, of course, stops the flow of gas. It protects because it interrupts gas service by fully shutting off the gas.

  For a gas utility, where continuity of service is of serious importance, this characteristic of automatic shutoff is a big disadvantage.

- o Containment. Automatic shutoff contains the gas. Like monitoring, it does not allow gas to blow into the atmosphere. It contains the gas within the piping.

- o Alerting. In general, shutting the gas off results in good notification. Usually it is quickly noticed. However, there could be situations where it is not detected immediately and the intervening lack of gas has undesirable or even serious results.

The next sections cover the three basic methods of overpressure protection in more detail.

PRESSURE RELIEF

Figure H-4 is a diagram of a typical relief valve installation. The purpose of the relief valve is to prevent outlet pressure from rising to an unsafe level when there is a regulator failure.

In general, a failure with the regulator would result in either too much or too little pressure downstream. The failure would leave the regulator in what could be called a "fail-open" condition (regulator too far open, even fully open .... too much gas flow) or a "failed-closed" condition (regulator too far closed, even fully closed .... not enough gas flow.) A relief valve, of course, is only useful in a "fail-open" regulator condition: too much gas flow, hence a rising above normal of the downstream pressure. Relief valves do nothing for a "failed-closed" regulator condition: too little gas.

A relief valve protects by discharging the excess gas into the atmosphere. As long as a regulator operates correctly and downstream pressure is normal, a relief valve remains closed. If the regulator fails, and allows too much gas to flow (a "fail-open" condition for the regulator), downstream pressure will increase. The relief valve will remain closed until pressure reaches its set-point. At that point it will begin opening and will continue to do so, as the pressure continues to rise. It will open far enough to discharge all of the excess gas into the atmosphere. When it reaches that point, there will be no further rise in the downstream pressure and, if the relief valve and its installation are correctly sized, the pressure downstream will not be high enough to be unsafe.

Keep in mind that the relief valve does not discharge all of the gas into the atmosphere. It only discharges the excess. There is still a normal flow for the load. Customers continue to get gas.

RELIEF VALVE SIZING

Sizing is vitally important. This applies not only to the relief valve itself, but to the piping of the entire installation. A relief valve must be big enough to handle the maximum emergency. When properly installed and maintained, relief valves are very dependable. The question is not so much whether or not one will work, but rather whether or not it is large enough to provide full protection during a maximum emergency.

When a relief valve is in full operation, it can discharge an enormous volume of gas into the atmosphere. For that reason they cannot be used everywhere, and this must be carefully considered when a relief valve installation is being planned and engineered. The vital questions are these: What happens with the gas after it leaves the relief valve? Will it disperse harmlessly? Or, could it create another emergency? This matter is addressed in 49 CFR 192.199(e).

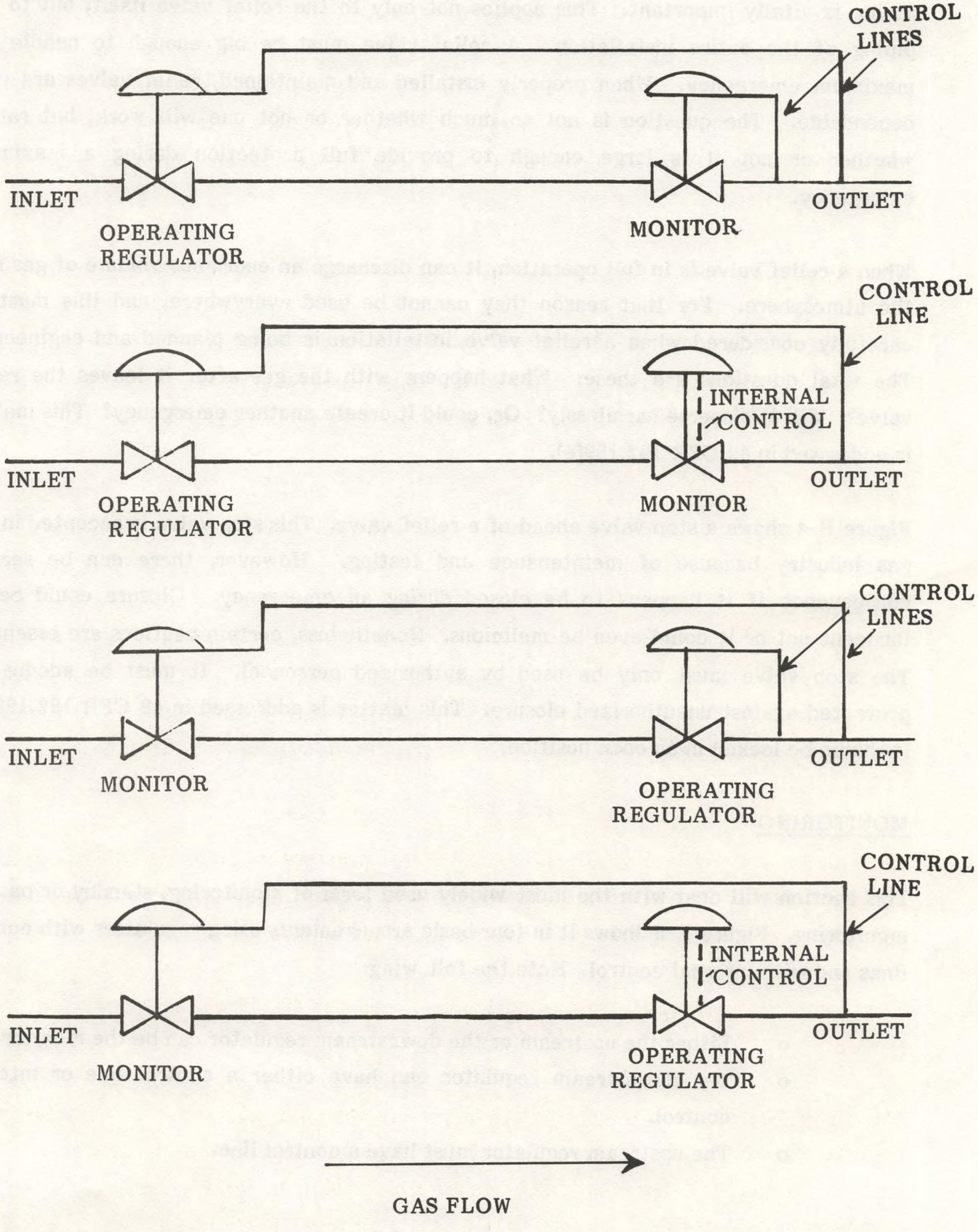
Figure H-4 shows a stop valve ahead of a relief valve. This stop valve is accepted in the gas industry because of maintenance and testing. However, there can be serious consequence if it happens to be closed during an emergency. Closure could be an innocent act or it could even be malicious. Nonetheless, certain cautions are essential. The stop valve must only be used by authorized personnel. It must be adequately protected against unauthorized closure. This matter is addressed in 49 CFR 192.199(h). It should be locked in an open position.

MONITORING

This section will deal with the most widely used form of monitoring, standby or passive monitoring. Figure H-5 shows it in four basic arrangements using regulators with control lines and with internal control. Note the following:

- o Either the upstream or the downstream regulator can be the monitor.
- o The downstream regulator can have either a control line or internal control.
- o The upstream regulator <u>must</u> have a control line.

Figure H-5 Standby Monitoring



Standby monitoring is sometimes confused with two-stage or double-cut regulation. The big difference, of course is in the control line for the upstream regulator. In standby monitoring, the control line for the upstream regulator goes all the way downstream. It does not connect between the regulators as in two-stage regulation. To repeat, the control line for the upstream regulator in standby monitoring goes on beyond the downstream regulator to a point somewhere in the outlet piping. That is the reason the upstream regulator in standby monitoring must have a control line, whereas in two-stage regulation the upstream as well as the downstream regulator can have either a control line or internal control.

Two-stage regulation can be used as a form of monitoring provided the two following conditions are met:

- o The system downstream of the second stage regulator (including the regulator) must be safe at the set-point pressure of the first stage regulator.

- o The second stage regulator must be safely rated for an inlet pressure as high as the maximum inlet pressure to the first stage regulator.

Referring again to Figure H-5, the set-point for the operating regulator is the normal outlet pressure, that is, the pressure normally required for the load.

The set-point for the monitor is higher. Because it is higher, the monitor is further open than the operating regulator (usually the monitor is wide open) and allows the gas to flow normally.

If the operating regulator "fails-open," the outlet pressure will rise. It will rise until the pressure reaches the set-point of the monitor. Then, the monitor will become the operating regulator to hold outlet pressure at its set-point.

The monitor set-point, of course, must not exceed the MAOP of the downstream piping system.

The difference between the set-points of the monitor and the operating regulator is not critical. However, the two should not be so close as to cause the monitor to interfere with the other. Other than this, monitor set-point is largely determined by the requirements of the installation and applicable practices and standards.

AUTOMATIC SHUTOFF

In automatic shutoff a special valve is used to shut off the gas completely if pressure reaches a preset level. During normal operation, the valve remains fully open and allows gas to flow freely.

If a regulator failure ("fail-open" failure), or something else, causes outlet pressure to rise, the automatic shutoff valve closes when pressure reaches its set-point.

The normal outlet pressure is the regulator's set-point. The set-point of the automatic shutoff valve will, of course, be higher. How much higher must be decided when planning and engineering the installation. It must not exceed the MAOP, that is, the maximum safe limit, of the downstream piping.

Automatic shutoff valves close automatically, but must be manually reset. This has the advantage of preventing an emergency from passing unnoticed. It also has an economic advantage because automatic reopening would greatly increase cost.

Shutting the gas off at times of emergency certainly is desirable. However, in the gas business, continuity of service is also important. This is probably the reason automatic shutoff has found only limited use in the gas industry. Pressure relief and monitoring are much preferred because they offer full protection while allowing a safe flow of gas to continue.

Automatic shutoff valves are available with control line or with internal control. Figure H-6 shows both diagrammatically. Note the following regarding one versus the other:

Internal Control

This offers a simpler installation because there is no control line. However, due to its internal control, it must be located downstream of the regulator. Therefore, upon closure everything upstream of the shutoff valve will be pressured to full inlet pressure.

This means that if the regulator has internal control, its main diaphragm will be exposed to full inlet pressure. This could result in severe damage, even to the extent of a burst

regulator. The same applies to a regulator with a control line if the control line is connected (the sensing point) between the regulator and the automatic shutoff valve. In sum, if an automatic shutoff valve with internal control is used, everything between it and the regulator, including the regulator itself, must be carefully checked for exposure to full maximum inlet pressure.

Moreover, if the outlet piping for the regulator is a larger size than the inlet piping, an internal control type automatic shutoff valve will, accordingly, be a larger size than one with a control line.

<u>Control Line</u>

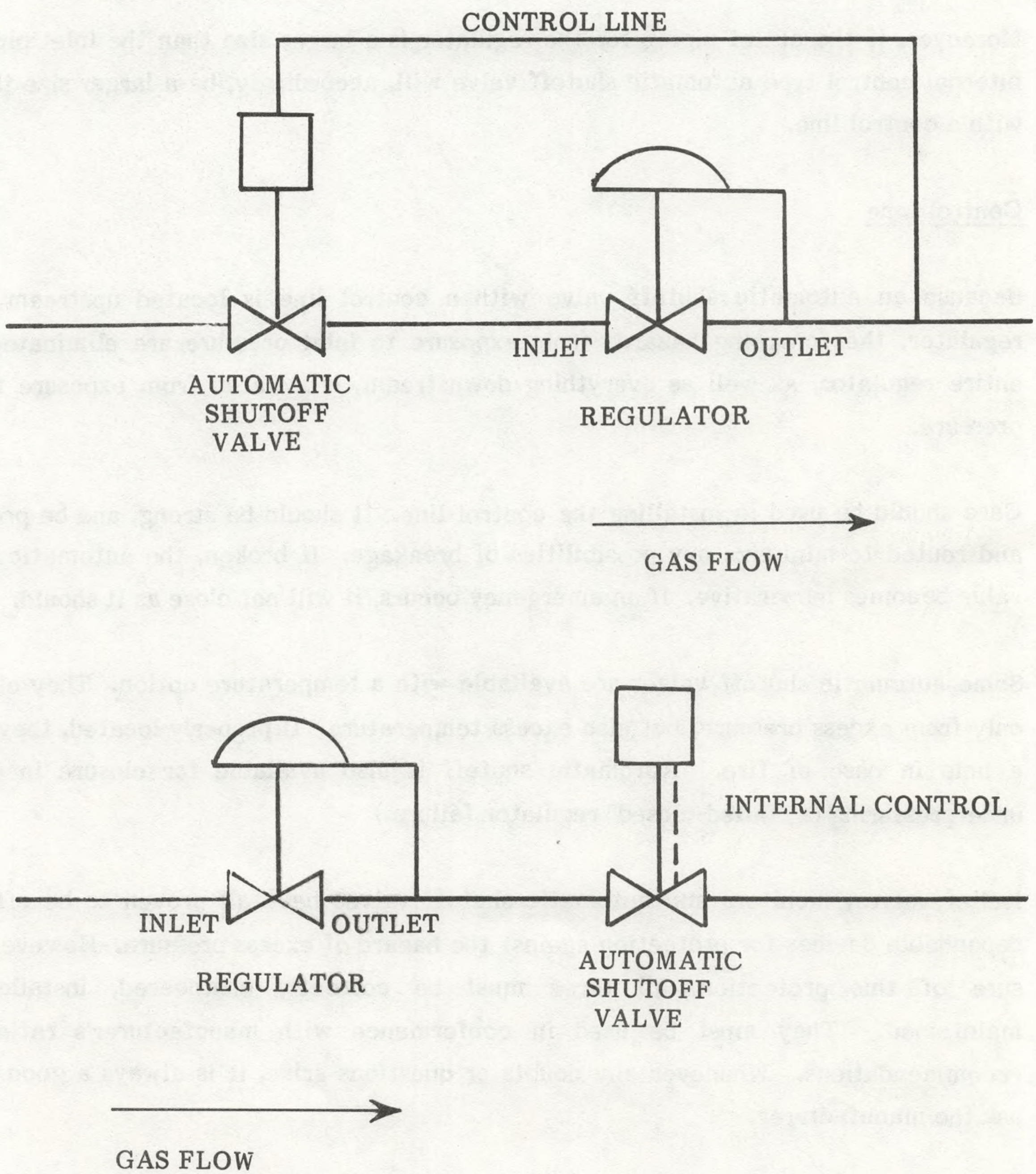
Because an automatic shutoff valve with a control line is located upstream of the regulator, the foregoing hazards from exposure to inlet pressure are eliminated. The entire regulator, as well as everything downstream, is isolated from exposure to inlet pressure.

Care should be used in installing the control line. It should be strong, and be protected and routed to minimize any possibilities of breakage. If broken, the automatic shutoff valve becomes inoperative. If an emergency occurs, it will not close as it should.

Some automatic shutoff valves are available with a temperature option. They close not only from excess pressure, but also excess temperature. If properly located, they can be a help in case of fire. Automatic shutoff is also available for closure in case of underpressuring (a "failed-closed" regulator failure.)

Relief valves, monitors and automatic shutoff valves have all proven to be effective, dependable devices for protection against the hazard of excess pressure. However, to be sure of this protection, all three must be correctly engineered, installed, and maintained. They must be used in conformance with manufacturer's ratings and recommendations. Whenever any doubts or questions arise, it is always a good idea to ask the manufacturer.

Figure H-6 Automatic Shutoff Valve Installations



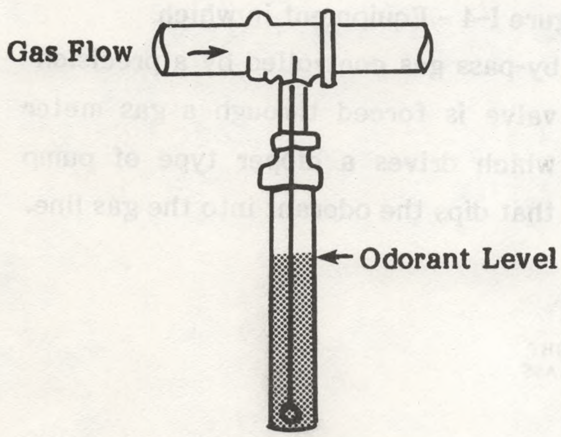
APPENDIX I

ODORIZATION EQUIPMENT

THIS APPENDIX WILL NORMALLY NOT APPLY TO MASTER METER OPERATORS OR LPG OPERATORS.

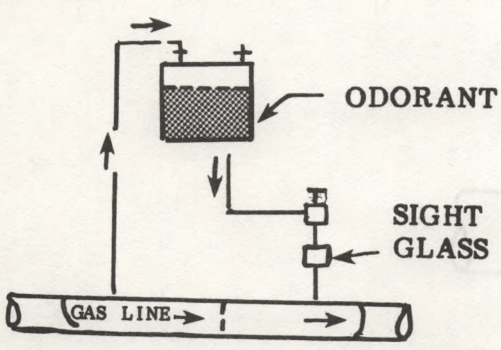
This appendix provides information for gas system operators who odorize their own gas. All of the equipment and illustrations refer to natural gas systems except for the last section of the appendix which addresses LP-Gas requirements.

The following are some illustrations and brief discussions of odorization equipment used by small natural gas operators.



Single-Unit wick odorizer

Figure I-1 - Equipment which odorizes the gas by having natural gas flow across a wick saturated with odorant. Generally used for individually odorized lines such as farm taps.



Drip-type odorizer

Figure I-2 - Equipment for introducing odorant from a storage tank directly into a gas stream through gravity flow. The odorant may be regulated by orifice float valves, or rotameters.

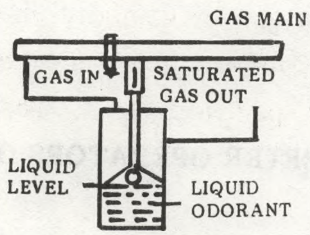
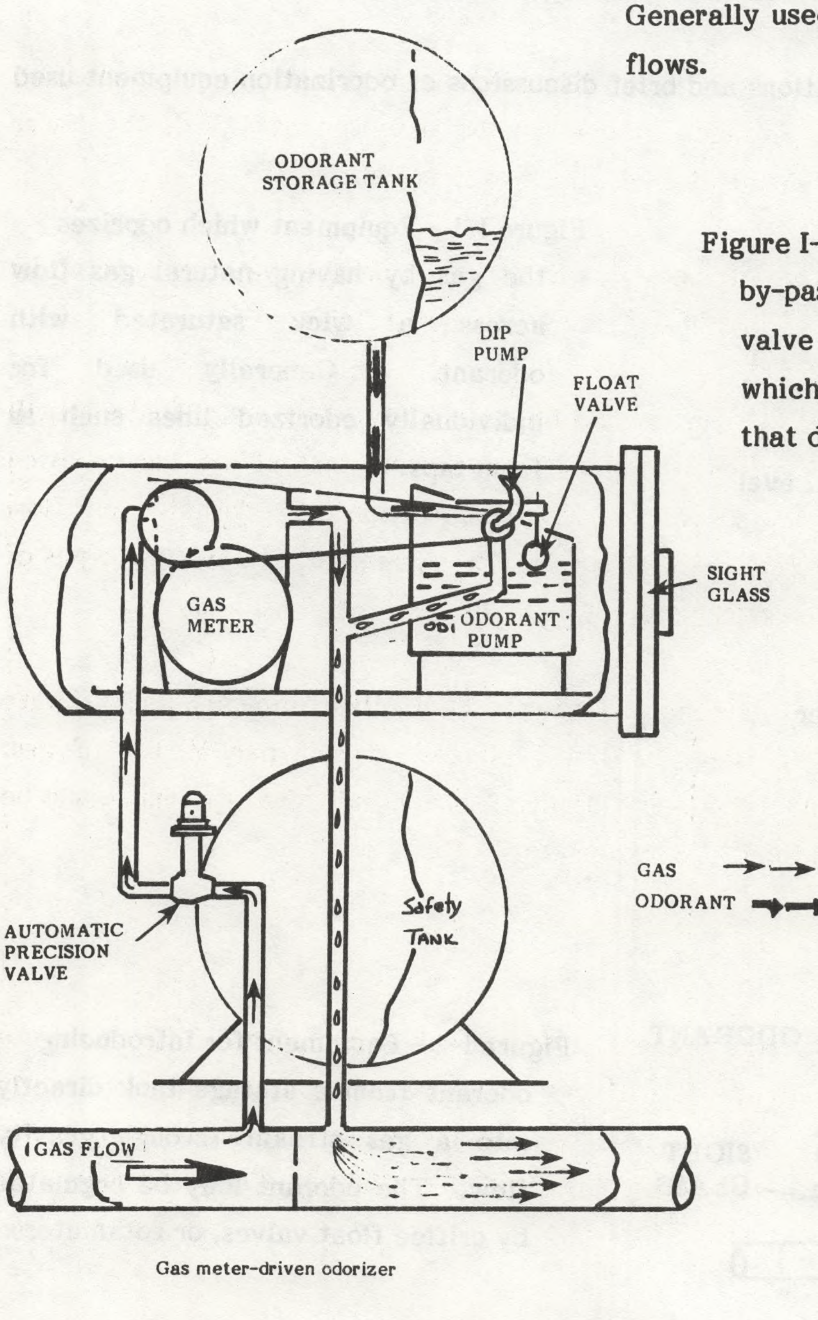


Figure I-3 - Equipment in which a portion of the main gas stream is diverted, by an orifice plate or partially closed valve in the line, through a tank provided with baffles or wicking. The odorant-saturated portion of the by-pass gas is then returned to the main stream. Generally used for low, more uniform flows.

Figure I-4 - Equipment in which by-pass gas controlled by a precision valve is forced through a gas meter which drives a dipper type of pump that dips the odorant into the gas line.



Gas meter-driven odorizer

Odorization equipment may need seasonal adjustments. Valves which regulate the amount of gas diverted into odorizer need to be adjusted between seasons of high flow of gas and low flow of gas (winter vs. summer.) Based on the equipment manufacturer's recommendation, develop these operational instructions for your specific system. These instructions should be included in your O&M plan.

Equipment Selection Considerations

- o Determine whether the natural gas being purchased from your supplier is odorized.

- o Determine whether the gas being purchased meets the minimum odorization level such that the presence of gas can be detected at 1/5 of the lower explosive level which is about 1 percent by volume in air.

- o Sizing of odorization equipment should be based on the material makeup by system, amount of gas used in system, and seasonal flows.

- o The injection rate of odorant should be determined by a consultant. It will vary for each individual gas system. Some factors that affect the injection rate are: type of odorant used, concentration of odorant, gas flow characteristics of system, type of odorization equipment, and age and types of material that make up piping system.

- o As a guideline for a mercaptan type odorant, the following approximate injection rate can be used: .5 to .75 pounds odorant per MMCF of gas. <u>(Caution: This is only a "ballpark" figure.)</u> Each individual system should be tested to determine the appropriate rate.

Type of Odorants

The odorants in common use at the present time are sulfur compounds. These have a characteristically "gassy" smell and are among the most odorous substances known. Generally, odorants are a blend of one or more of the mercaptans, aliphatic sulfides, or cyclic carbon sulphur ring compounds. The detection of the odorants is based upon their smell or their chemical composition.

The human sense of smell is very discerning and can detect mercaptans at a concentration of only 1 ppb, which is currently beyond the capabilities of most instruments. The sulfur content of the odorants in the gas stream can be measured by gas analysis, which may then be used to determine if there is sufficient odorant.

The types of detectors of importance are the odorometer, titrators, and the odotron. Of these instruments, the most common which would be used is the odorometer. At the present time, most operators of small gas systems who odorize their own gas need not purchase an odorometer.

Discussion of Odorometer

The odorometer is used to determine the lowest concentration at which gas can be detected through odor. The unit is actually a gas detector which indicates the percent of gas by volume in a sample which is also sniff tested. To determine the odor threshold level, the unit is used in an area where it can draw in fresh air and be connected to a gas source. A blower in the unit draws ambient air through the analyzer and out the exhaust chamber. Gas which has been odorized is then slowly admitted to the intake of the blower where it is mixed with ambient air. The operator continually "sniffs" the exhaust gas-air mixture. When he first detects an odor, he then determines the concentration of gas in the mixture by chart readings.

Monitoring Techniques

- Operators of master meter or small gas systems should, on a periodic basis verify the odor level with the gas company or have a consultant run an odorometer test on the gas in system to determine if it is properly odorized. The best time would be when there is a low usage of gas by customers. Operators should check with their respective states to see whether they have additional requirements.

- Operators should include as an operating procedure the requirement that "sniff tests" be made whenever a meter set, repair to system, or leak check is made. A "sniff test" is when one or more observers smells gas from an open valve, or gas burner. The name of the person, the date, and location of where the test is conducted, should be kept on file.

- o Operators should make a "sniff test" at extremities of the system at least every other month.

LP-Gas Odorization Requirements

ALL LP-gases must be odorized by the addition of a warning agent of such character that the gas is detectable, by a distinct odor, down to a concentration in air of not over one-fifth the lower limit of flammability. The LP-gas purchased should be odorized by your supplier before you purchase it. Use the bill of lading for evidence of odorant.

Guideline: experience has shown that ethyl mercaptan in the ratio of 1.0 pound per 10,000 gallons of liquid LP-gas has been recognized as an effective odorant.

Research on odorants has shown that thiophane (tetrahydrothiophene) in a ratio of at least 6.4 pounds per 10,000 gallons of liquid LP-gas also satisfies the requirements.

Properties of LP-Gas
(including limits of flammability)

	Commercial Propane NLP-GA Av.	Commercial Butane NLP-GA Av.
Vapor Pressure in psig at.		
70 F	132	17
100 F	205	37
105 F	216	41
130 F	300	69
Specific Gravity of Liquid at 60 F	0.509	0.582
Initial Boiling Point at 14.7 psia, Degrees F	-51	15
Weight per Gallon of Liquid at 60 F, lb.	4.24	4.81
Specific Heat of Liquid, Btu/lb. at 60 F	0.588	0.549
Cu. ft of Vapor per Gallon at 60 F	36.39	31.26
Cu. ft of Vapor per Pound at 60 F	8.58	6.51
Specific Gravity of Vapor (Air = 1) at 60 F	1.52	2.01
Ignition Temperature in Air, Degrees F	920-1120	900-1000
Maximum Flame Temperature in Air, Degrees F	3,595	3,615
Limits of Flammability in Air, Percent of Vapor in Air-Gas Mixture:		
(a) Lower	2.15	1.55
(b) Upper	9.60	8.60
Latent Heat of Vaporization at Boiling Point:		
(a) Btu per Pound	185	167
(b) Btu per Gallon	785	808
Total Heating Values after Vaporization:		
(a) Btu per Cubic Foot	2,516	3,280
(b) Btu per Pound	21,591	21,221
(c) Btu per Gallon	91,547	102,032

(from NFPA-58, 1979)

APPENDIX J

WELDING REQUIREMENTS

(Form 49 CFR Part 192, Subpart E)

THIS APPENDIX WILL NORMALLY NOT APPLY TO MASTER METER OPERATORS OR LPG OPERATORS.

How can I determine whether my pipeline welding is performed as required?

1. Welding must be performed under established written welding procedures as appropriate to either section 2 of API Standard 1104 or section IX of ASME Boiler and Pressure Vessel Code. For typical pipeline welding, API 1104 would most likely be used and will be discussed.

   The written welding procedure must include:

   a. Records of the complete results of the procedural qualification test.

   b. Procedural Specification

      (1) Identifying the process
      (2) Identifying the materials
      (3) Identifying the wall thickness groups
      (4) Showing a joint design sketch
      (5) Designating filler metal and number of beads
      (6) Designating electrical characteristics
      (7) Designating flame characteristics
      (8) Designating position or roll welding
      (9) Designating direction of welding
      (10) Designating maximum time lapse between passes
      (11) Designating type of line-up clamp and removal criteria
      (12) Designating type of cleaning tools used
      (13) Specifying preheat and post heat practices
      (14) Designating composition of gas and range of flow rate

(15) Designating type and size of shielding flux

(16) Designating range of speed of travel for each pass

c. Essential Variables

Most changes in b. require requalification of the welding procedure. (Refer to paragraph 2.4 API 1104.)

d. Welding and Testing of Test Joint

(1) Preparation of Specimen

(2) Destructive Tests - Butt Welds

(a) Tensile Strength Test

(b) Nick Break Test

(c) Root and Face Bend Test

(d) Side Bend Test

(3) Destructive Test - Fillet Welds

Break in Weld as specified

2. Welding must be performed by welders who are qualified for the welding procedure to be used.

a. The welder shall be qualified under one of the applicable requirements specified.

(1) Transmission Pipelines

(a) Section 3 of API 1104

or (b) Section IX of ASME Boiler and Pressure Vessel Code

(2) Distribution Pipeline

(a) Section 3 of API 1104

(b) Section IX of ASME Boiler and Pressure Vessel Code

or (c) Section I of Appendix C, 49 CFR Part 192 (Not acceptable for service line to main connection welding.)

(3) Service Line Connections to Mains

(a) Section 3 of API 1104

(b) Section IX of ASME Boiler & Pressure Vessel Code

or (c) Sections I and II of Appendix C, 49 CFR Part 192

b. Welder qualification under Section 3 of API 1104.

(1) Perform qualification test as specified in the written welding procedure in the presence of your company's representative.

(2) Essential Variables (Certain changes require requalification.)

(a) For single qualification refer to 3.11 of API 1104

or (b) For multiple qualification refer to 3.21 of API 1104.

(3) Welding and Testing of Test Joint

(a) Preparation of Specimen(s)

(b) Visual Examination

(c) Destructive Test - Butt Welds

Determine if all or part of these tests are required:

1 Tensile Strength Test

2 Nick Break Test

3 Root and Face Bend Test

4 Side Bend Test

(d) Destructive Tests - Fillet welds

Break in weld as specified

(e) Visual Inspection

NOTE: Non-destructive radiographic inspection of Butt Welds only can be done in lieu of (3) (c) above. This is your option. Welders qualifying by non-destructive testing cannot weld on compressor station pipe and components. The standards of acceptability for radiographic inspection are specified in paragraph 6.0 of API 1104.

(4) Keep the following records

(a) Detailed test results for each welder

(b) Test of qualified welders and the procedure(s) for which they are qualified

c. Welder qualification under Section I of Appendix C, 49 CFR Part 192

(1) Perform qualification test on pipe 12" or less in diameter.

(2) Use position welding.

(3) Preparation must conform to written welding procedure.

(4) Destructive Test

(a) Root Bend Test

(5) Visually inspect.

(6) Keep the following records:

(a) Detailed test results for each welder.

(b) Test of qualified welders under this procedure.

d. Welder qualification under Section I and II of Appendix C. 49 CFR Part 192

(1) Perform c. above.

(2) Weld service line connection fitting to a pipe typical of your main using similar position as you would in actual production welding.

(3) Destructive Test - Break (or attempt to) the fitting off the run pipe.

(4) Visually inspect.

e. Remain qualified under Section 3 of API 1104 or Section IX of ASME Boiler and Pressure Vessel Code if:

Within the preceding 6 calendar months he/she has welded with the particular welding process (either test or production welding is acceptable), he/she may perform a modified test by having one weld tested satisfactorily either destructively or nondestructively. (Refer to 2b(3) for required procedure.)

f. Remain qualified under either Section I or II of Appendix C if:

(1) Within the preceding 7 1/2 calendar months but at least twice each calendar year he/she has had one production weld cut out, tested, and found acceptable in accordance with the initial qualification test.

NOTE: Welders who work only on service lines 2" or smaller in diameter may be tested in each 6-month period under Section III of Appendix C in lieu of f (1) above but at the same intervals.

or (2) Within the preceding 15 calendar months, but at least once each calendar year he/she has requalified under Appendix C. 49 CFR Part 192.

3. Production Welding

a. Use a welder qualified in a qualified welding procedure.

b. The following items should be part of the written welding procedure:

(1) Weather protection - 49 CFR 192.231

(2) Preparation - 49 CFR 192.235

(3) Preheating (Under specified conditions - 49 CFR 192.237)

(4) Stress relieving (Under specified conditions - 49 CFR 192.239)

(5) Visual Inspection - 49 CFR 192.241

(6) Non-Destructive Testing (Under specified condition - 49 CFR

192.243) Must meet standards of acceptability in Section 6 at API 1104.

c. Miter Joint Restrictions

The use of miter joints is restricted as follows:

(1) If MAOP produces a hoop stress of 30% or more of SMYS, the joint cannot deflect the pipe more than 3 degrees.

(2) If MAOP produces a hoop stress or more than 10% of SMYS but less that 30%, the joint cannot deflect the pipe more than 12 1/2 degrees and must have at least one pipe diameter separation from another miter joint.

(3) If MAOP produces a hoop stress of 10% of SMYS or less, the joint cannot deflect the pipe more than 90 degrees.

d. Repair or removal of defect requirements are as follows:

(1) Remove or repair all welds that fail to pass the nondestructive test requirements. (Standards of acceptability in section 6 of API 1104.)

(2) Remove all welds which contain cracks that are more than 8% of the weld length.

(3) Repairs must have the defect removed down to clean metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. Inspect the repaired weld.

(4) Repair of a crack, or any defect in a previously repaired area, must be in accordance with written weld repair procedures that have been qualified under (1) above on page 196 of this Guidance Manual.

APPENDIX K

PLASTIC PIPE: REGULATIONS ON QUALIFYING JOINING PROCEDURES AND QUALIFYING PERSONS

§ 192.283 Plastic pipe; qualifying joining procedures.

(a) *Heat Fusion, Solvent Cement, and Adhesive Joints.* Before any written procedure established under § 192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

(1) The burst test requirements of—

(i) In the case of thermoplastic pipe, paragraph 8.6 (Sustained Pressure Test) or paragraph 8.7 (Minimum Hydrostatic Burst Pressure) of ASTM D2513; or

(ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517;

(2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

(3) For procedures intended for non-lateral pipe connections, follow the tensile test requirements of ASTM D638, except that the test may be conducted at ambient temperature and humidity. If the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.

(b) *Mechanical Joints.* Before any written procedure established under § 192.273(b) is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting 5 specimen joints made according to the procedure to the following tensile test:

(1) Use an apparatus for the test as specified in ASTM D638-77a (except for conditioning).

(2) The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength.

(3) The speed of testing is 5.0 mm (0.20 in) per minute, plus or minus 25 percent.

(4) Pipe specimens less than 102 mm (4 in) in diameter are qualified if the pipe yields to an elongation of no less than 25 percent or failure initiates outside the joint area.

(5) Pipe specimens 102 mm (4 in) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 55.6° C (100° F) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress.

(6) Each specimen that fails at the grips must be retested using new pipe.

(7) Results obtained pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness.

(c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

(d) Pipe or fittings manufactured before July 1, 1980, may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

(49 U.S.C. 1672, 1804, with regard to offshore gathering lines; 49 CFR 1.53 and Appendix A of Part 1)

[Amdt. 192-34A, 45 FR 9935, Feb. 14, 1980, as amended by Amdt. 192-34B, 46 FR 39, Jan. 2, 1981]

§ 192.285 Plastic pipe; qualifying persons to make joints.

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by—

(1) Appropriate training or experience in the use of the procedure; and

(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be—

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(2) In the case of a heat fusion, solvent cement, or adhesive joint:

(i) Tested under any one of the test methods listed under § 192.283(a) applicable to the type of joint and material being tested;

(ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

(iii) Cut into at least 3 longitudinal straps, each of which is—

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(c) A person must be requalified under an applicable procedure, if during any 12-month period that person—

(1) Does not make any joints under that procedure; or

(2) Has 3 joints or 3 percent of the joints made, whichever, is greater, under that procedure that are found unacceptable by testing under § 192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in his system is qualified in accordance with this section.

(49 U.S.C. 1672; 49 U.S.C. 1804 with regard to offshore gathering lines; 49 CFR 1.53 and Appendix A of Part 1)

This appendix will normally not apply to master meter operators or LPG operators.

APPENDIX L

SERVICE LINE DRAWINGS, MAIN CONNECTIONS TESTING, AND SIMPLE REPAIR CLAMPS

THIS APPENDIX WILL NORMALLY NOT APPLY TO MASTER METER OPERATORS OR LPG OPERATORS.

This appendix contains the following:

- **Sample drawings of some typical service lines with their main connections.**
- **Pressure testing requirements for services and mains.**
- **Two illustrations of some simple repairs clamps for use on steel pipe. Instructions for their installation are included.**

Please note that:

- **<u>These drawings are for illustration purposes only</u>. There are many other acceptable ways to put together a service. Make sure a qualified person designs your mains and services.**
- **There are hundreds of repair fittings on the market. Have a qualified person select the best for your system.**
- **When using mechanical compression type fittings to join steel pipe, it is very important that the compression type fittings be equipped with armored or bonding type gaskets. This is necessary to maintain continuity for cathodic protection and pipe tracing purposes. If electrical isolation is required, use an insulating type fitting only at point of isolation.**

The chart on the following page provides test conditions for service lines and applies to each of the six subsequent illustrations in this Appendix.

TEST CONDITIONS FOR SERVICE LINES				
Other Than Plastic				Plastic
Maximum operating pressure	Less than 1 psig	1 psig to 40 psig	Over 40psig but less than 100 psig	0-100 psig
Test Medium	Water Air Natural Gas Inert gas	Water Air Natural Gas Inert gas	Water Air Natural Gas Inert gas	Water Air Natural Gas Inert gas (See Note(1)
Maximum test pressure	See Note(2)	See Note(2)	See Note(2)	3 x design pressure
Minimum test pressure	See Note(3)	50 psig	90 psig See Note(4)	50 psig or 1.5 x maxi mum operat ing pressure whichever is greater
Recommended minimum test duration	5 Minute	5 Minute	See Note(4)	5 Minute

Notes: For sample form See Appendix C, Form 16

(1) Temperature of thermoplastic material must not exceed 100 F during test.

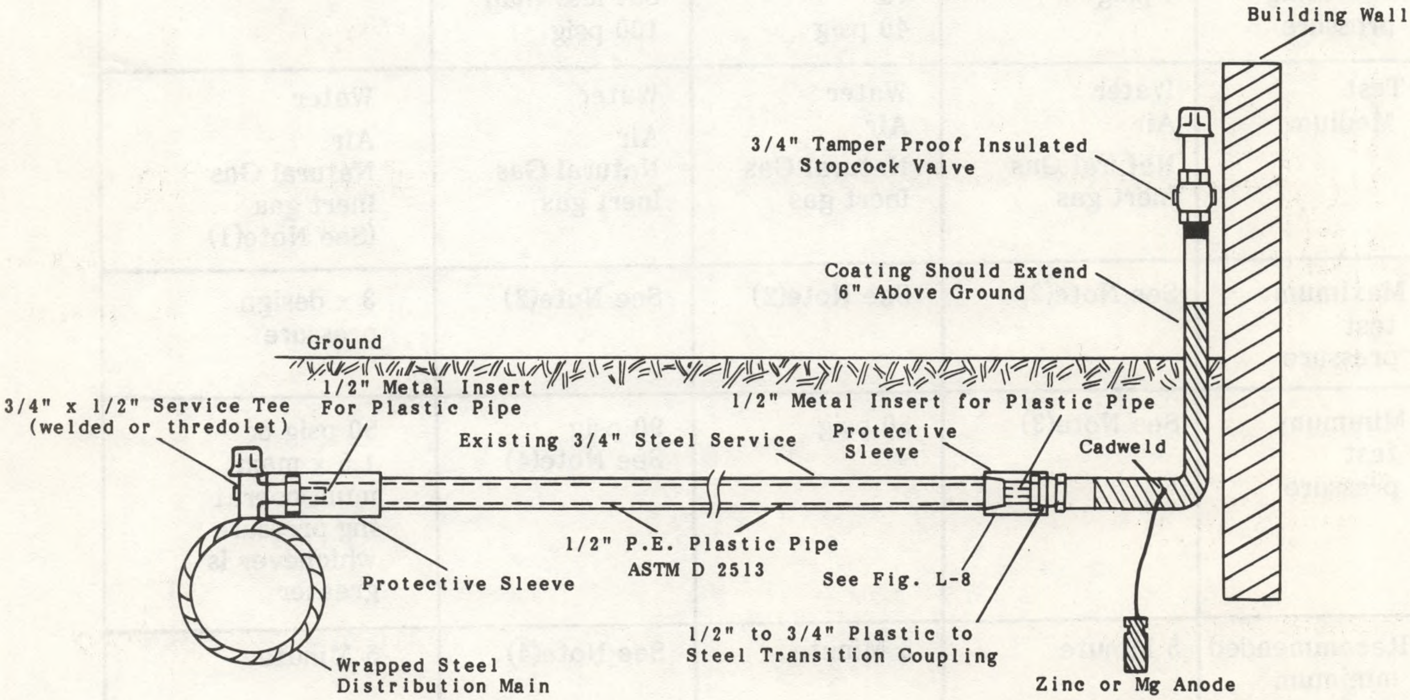
(2) Refer to 192.503(c) for limitations which testing with air, natural gas or inert gas. Limited also to the design pressure of service line component (192.619).

(3) Recommended practice is a minimum of 10 psig.

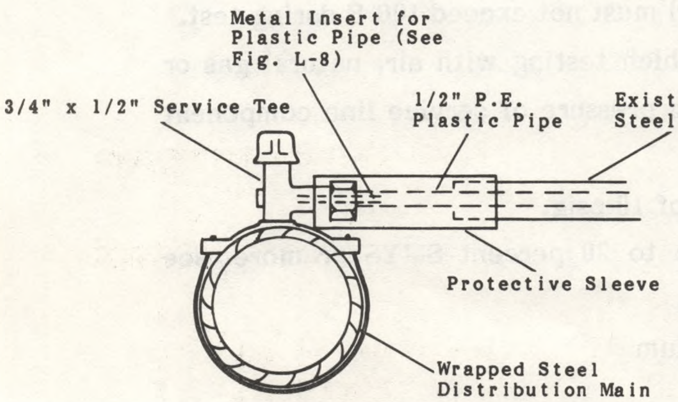
(4) Whenever test pressure stresses pipe to 20 percent SMYS or more, see 192.511(c) for additional requirements.

(5) LP-Gas may not be used as a test medium

Figure L-1 1/2" Plastic Pipe Inserted into a 3/4" Existing Service Line (for illustration purposes only; see page 203 for testing requirements)

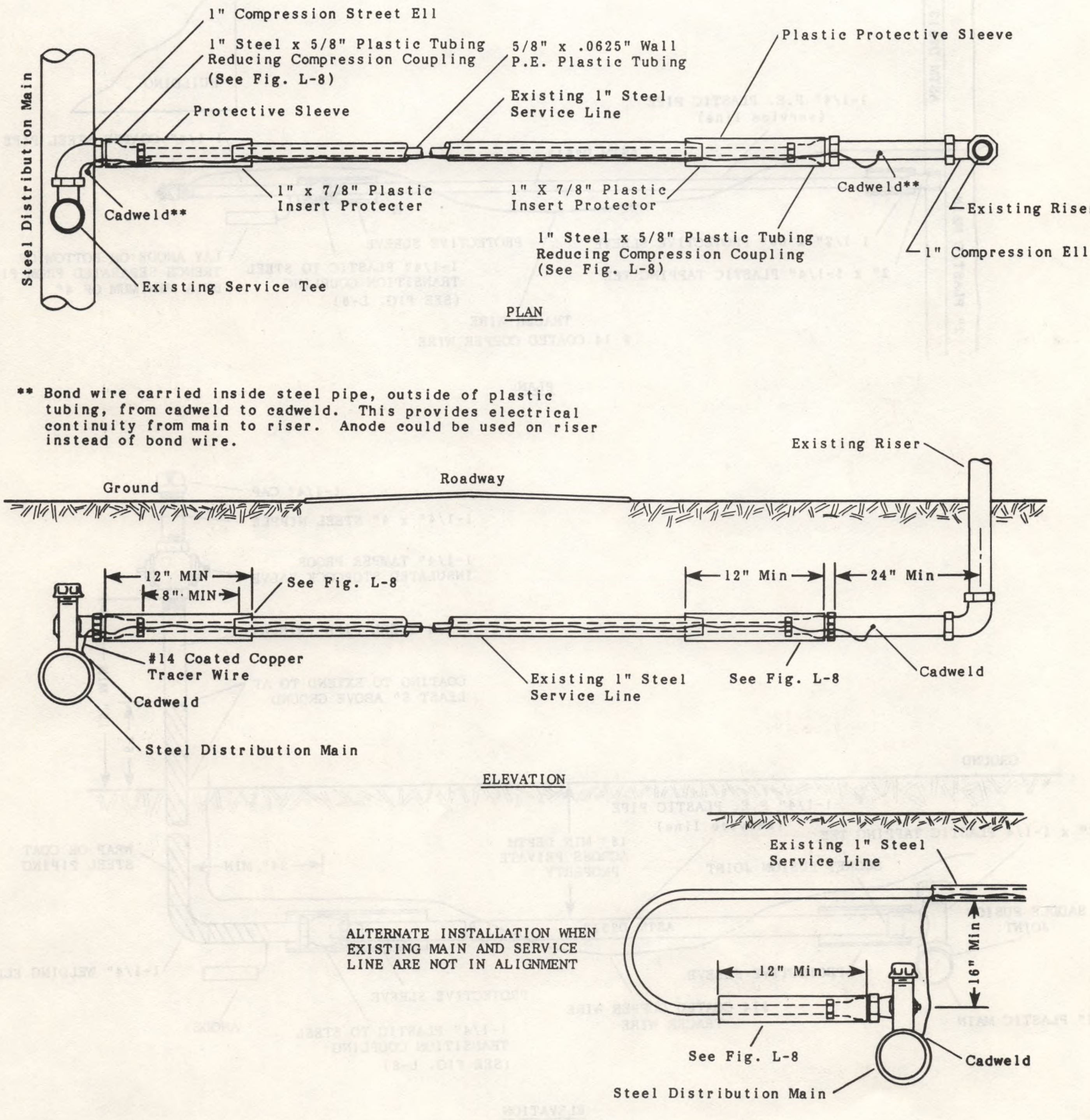


ELEVATION



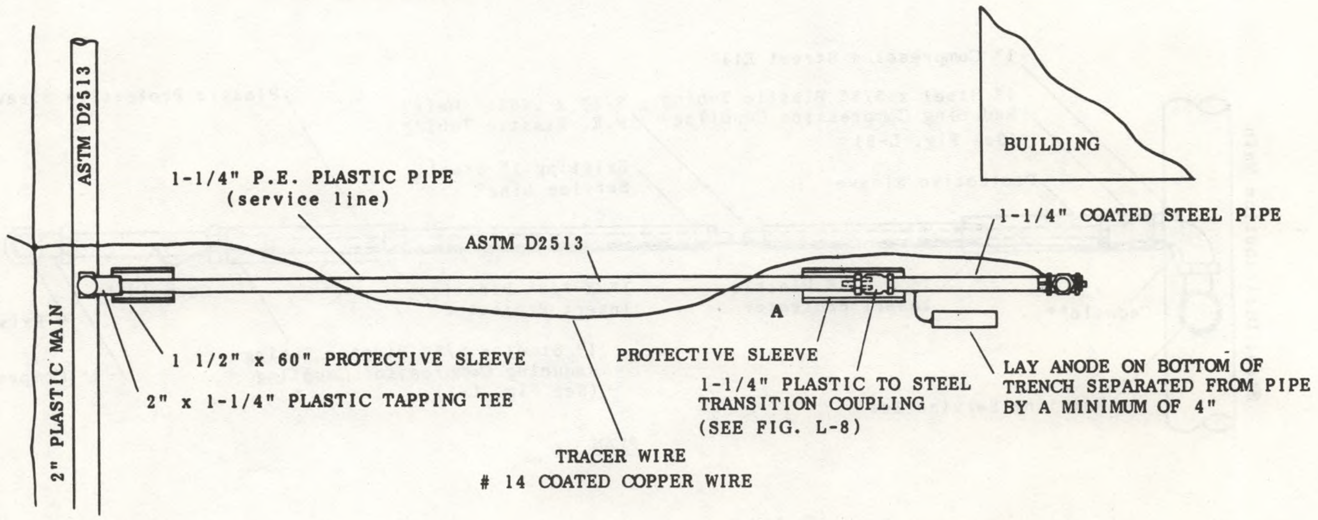
ALTERNATE SERVICE CONNECTION

Figure L-2 5/8" P.E. Plastic Tubing Inserted Into Existing 1" Metallic Line (for illustration purposes only; see page 203 for testing requirements)

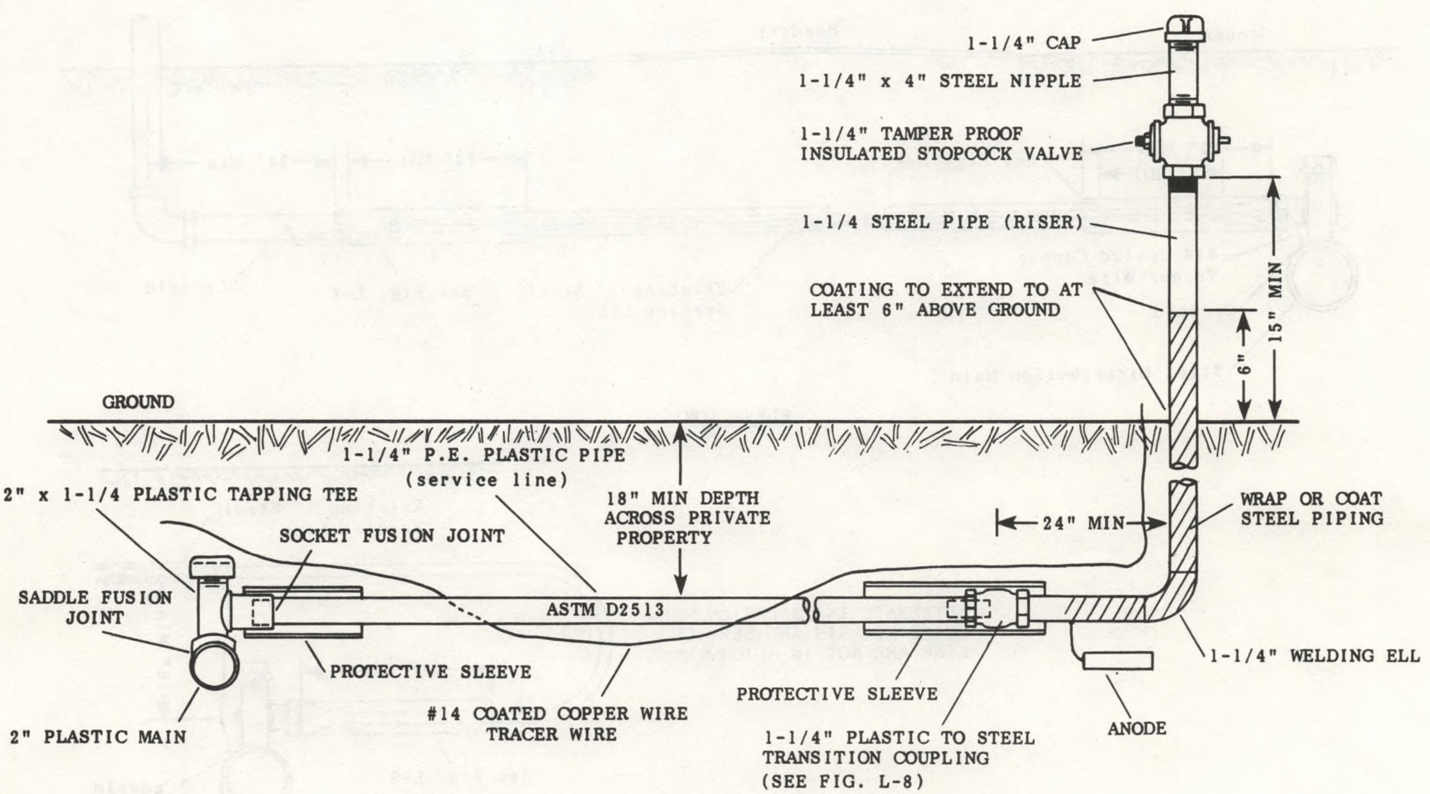


** Bond wire carried inside steel pipe, outside of plastic tubing, from cadweld to cadweld. This provides electrical continuity from main to riser. Anode could be used on riser instead of bond wire.

Figure L-3 **1 1/4" Plastic Service Line From 2" PE Plastic Main (for illustration purposes only; see page 203 for testing requirements)**



PLAN



ELEVATION

Figure L-4 1 1/4" PE Plastic Service Line From Steel Main (for illustration purposes only; see page 203 for testing requirements)

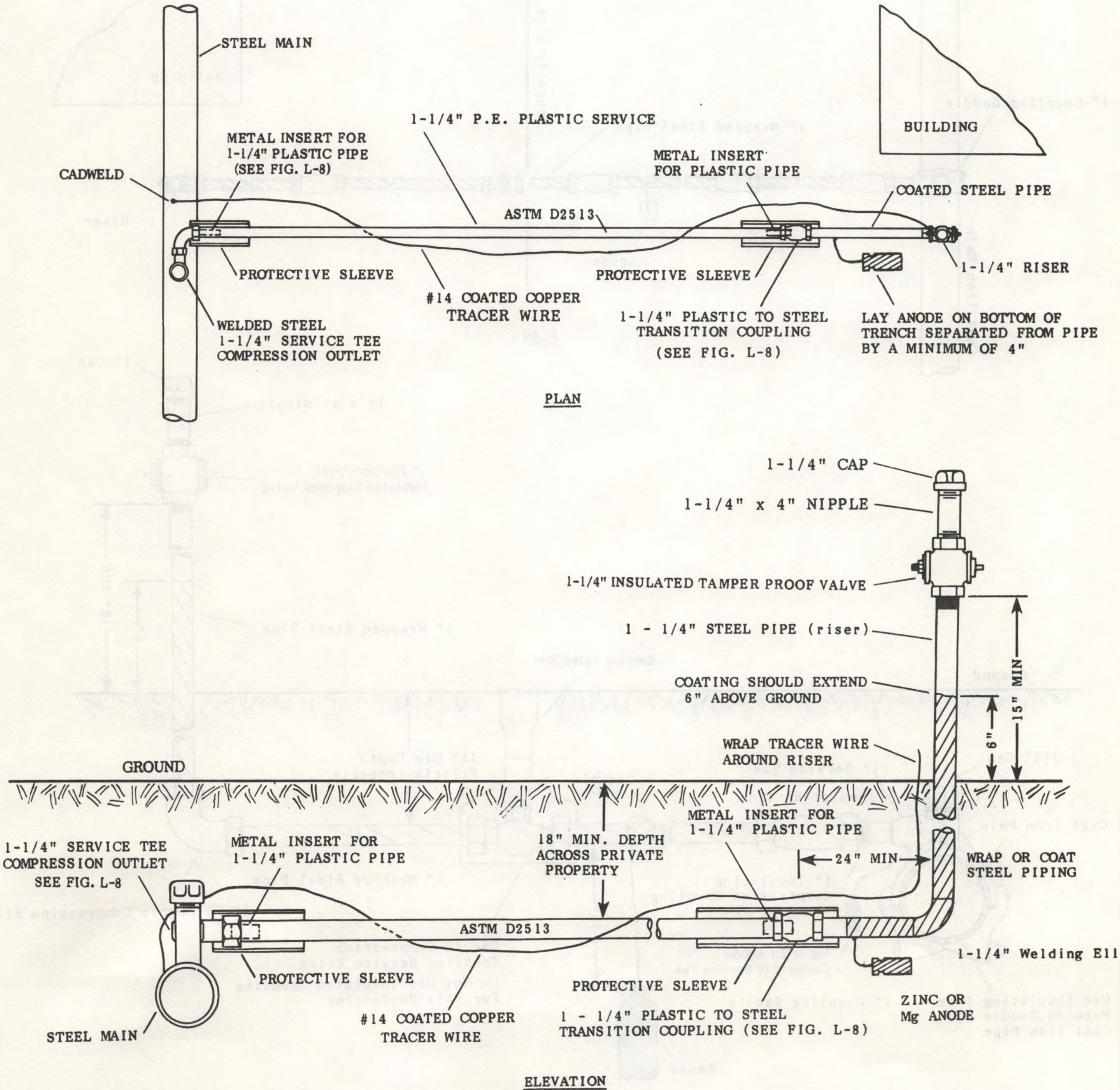
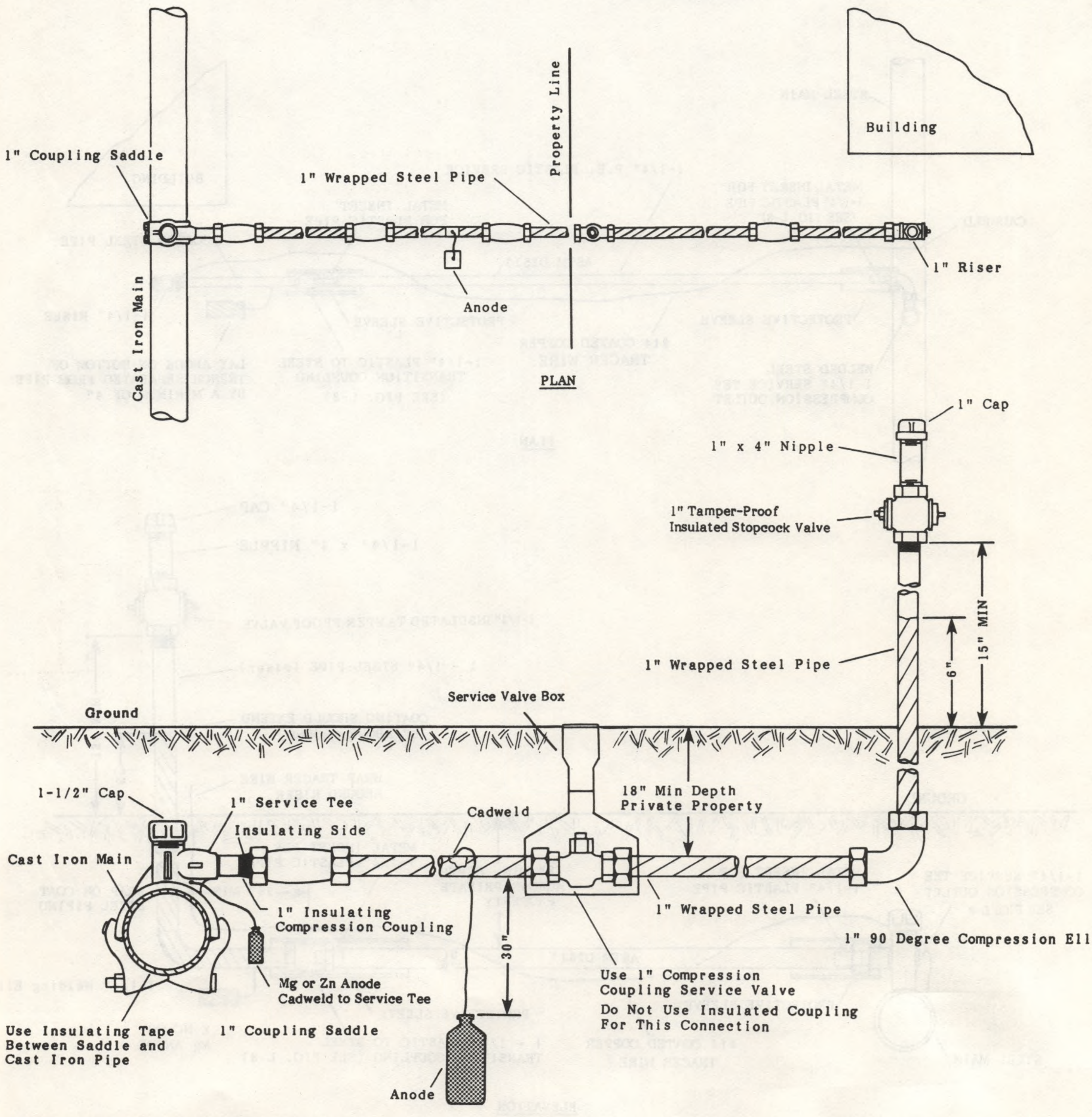


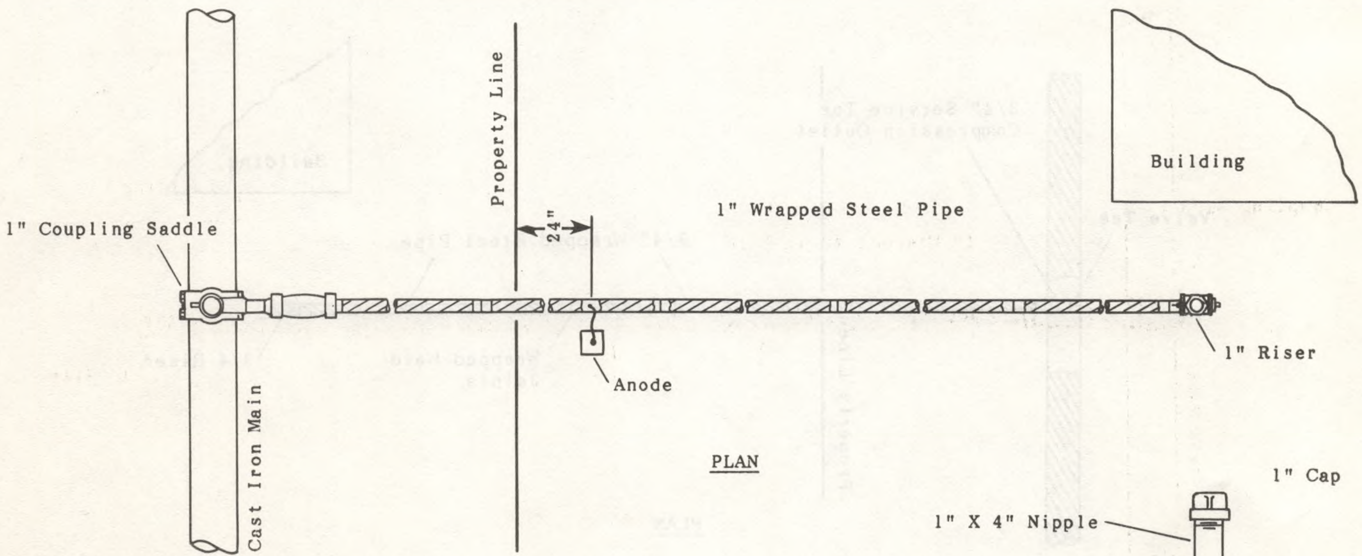
Figure L-5 Non-Welded 1" Service Line From Cast Iron Main (for illustration purposes only; see page 203 for testing requirements)



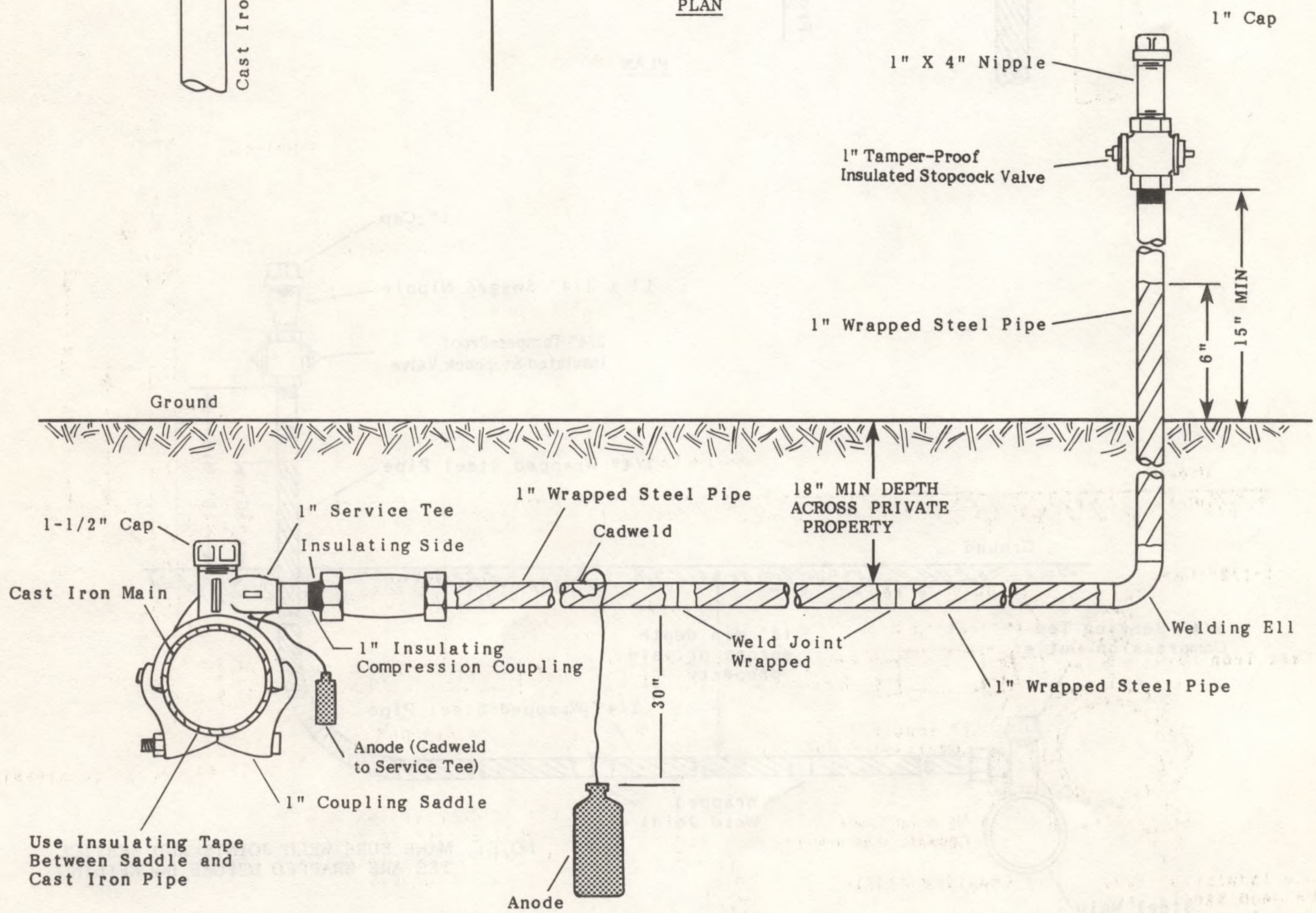
NOTE: COAT OR WRAP ALL COMPRESSION COUPLINGS AND THE SERVICE TEE BEFORE BACKFILING

ELEVATION

Figure L-6 Welded 1" Steel Service Line From Cast Iron Main (for illustration purposes only; see page 203 for testing requirements)



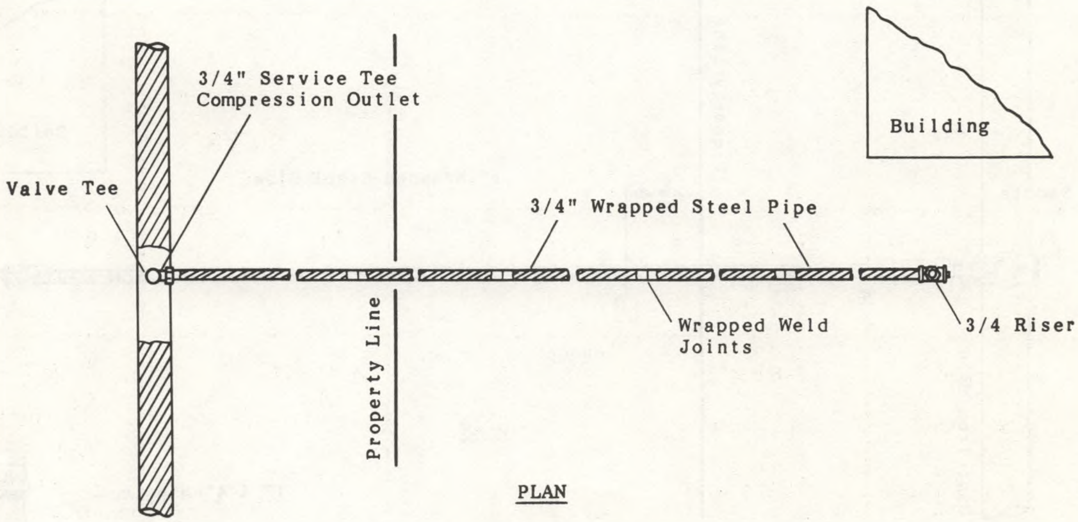
PLAN



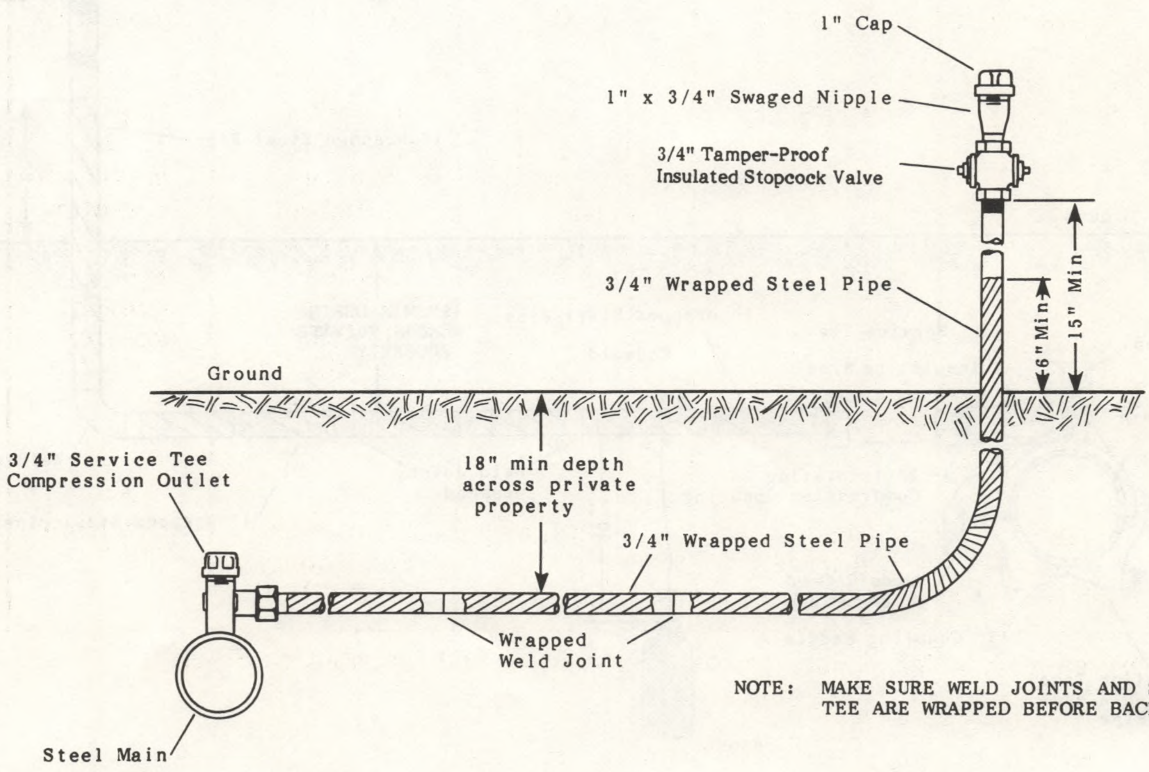
ELEVATION

NOTE: COAT OR WRAP ALL COUPLINGS AND WELDED JOINTS AND THE SERVICE TEE BEFORE BACKFILING

Figure L-7 Welded 3/4" Service Line From Steel Main
(for illustration purposes only; see page 203 for testing requirements)



PLAN



NOTE: MAKE SURE WELD JOINTS AND SERVICE TEE ARE WRAPPED BEFORE BACKFILING

ELEVATION

TEST CONDITIONS FOR PIPELINES OTHER THAN SERVICE LINES[1]

This table is presented as a guide to the application of the test requirements in 49 CFR 192.65, 192.143 192.503, 192.505, 192.509, 192.513 and 192.619 as they apply to pipelines other than service lines.

	Other Than Plastic				Plastic
	Under 30% SMYS			30% SMYS[2] and over	
Maximum operating pressure	Less than 1 psig	1 psig but less than 100 psig	100 psig and over[2]	All pressures	All pressures
Test medium	Water Air Air Natural gas Inert gas	Water Natural gas Inert gas	Water Air Natural gas Inert gas See Note (1)	Water Air Natural gas Inert gas	Water Air Natural gas Inert gas See Note (2)
Maximum test pressure	See Note (3)	See Note (3)	See Note (3)	See Note (3)	3x design pressure
Minimum test pressure	10 psig	90 psig	Maximum operating pressure multi-plied by class location factor in 192.619 (a)(2)(ii) See Note (1) & (4)	Maximum operating pressure multiplied by class location factor in 192.619 (a)(2)(ii) See Notes (4) & (5)	50 psig or 1.5 x maximum operating pressure which-ever is greater
Minimum test duration	See Note (6)	See Note (6)	1 Hour and See Notes (4) & (6)	8 Hours and See Notes (6) & (7)	See Note (6)

[1]Information derived from ASME Guide For Gas Transmission and Distribution Piping Systems-1980

[2]This column will normally not apply to a master meter operator

NOTES: to preceding table (all numbered references are to Title 49, CFR)

(1) Whenever test pressure is 20 percent SMYS (or greater), and the test medium is natural gas, inert gas, or air, the line must be checked for leaks. Either check by (a) a leak test at a pressure greater than 100 psig but less than 20 percent SMYS or (b) "walking the line" while the pressure is held at 20 percent SMYS (192.507(b)). "Walking the line" means patrolling the line to see if dirt blows or you hear gas.

(2) Temperature of thermoplastic material must not exceed 100 F during test.

(3) Refer to 192.503(c) for limitations when testing with air, natural gas or inert gas. (There are no limitations for water test.) For all test media, strength of all pipeline components in test section must be taken into consideration when determining the maximum test pressure.

(4) Refer to 192.65(b) for pipe transported before November 12, 1970.

(5) Refer to 192.505(a) for testing criteria covering pipelines located within 300 feet of building and 192.505(b) covering compressor stations.

(6) Duration determined by volumetric content of test section and instrumentation in order to ensure discovery of all potentially hazardous leaks.

(7) Refer to 192.505(e) for fabricated units and short section of pipe.

Figure L-8

The following illustrates a steel to plastic pipe connection using a compression coupling. There are other sizes of connections. Refer to specific manufacturer's instructions for coupling used.

Figure L-8

DRESSER

GAS PRODUCT INSTALLATION MANUAL

Style 90 Couplings and Fittings with "PLASTI-LOK"™ Compression Ends for PP & SP

SAMPLE

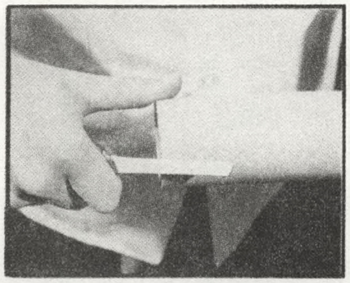


Fig. 1.

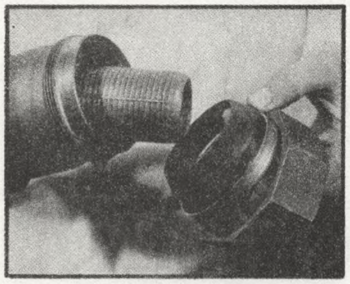


Fig. 2.

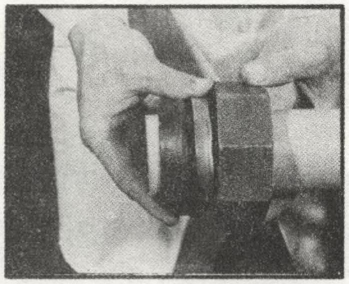


Fig. 3.

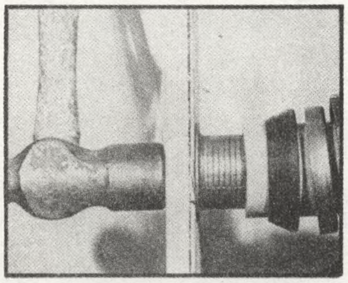


Fig. 4.

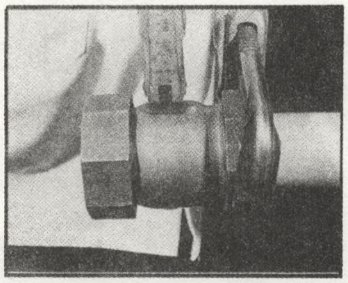


Fig. 5.

Style 90 PP and SP Couplings and Fittings for use on Polyethylene to Polyethylene and transition from Steel to Polyethylene pipe. Transition couplings are furnished with ball lock gasket and nut on steel end.

I. Polyethylene Pipe ("Plasti-Lok")™ End:

1. P.E. pipe surface must be clean and free of linear scratches or gouges that would affect the sealing ability of gasket for not less than 3" from end of pipe. Squareness of the cut must be such that when insert is in place with flange butted to the pipe end, there shall be no gap between flange and pipe end in excess of ⅛". Use a pipe cutter or miter box to insure squareness. Remove all burrs from inside and outside of plastic pipe after cutting. (Fig. 1)

2. Remove nut, gasket, retainer cup, and lock insert (Fig. 2).

3. Assemble nut, gasket, and retainer cup as a unit and slip onto pipe end before installing lock insert into plastic pipe (Fig. 3) (lock insert flange is larger in diameter than the I.D. of the gasket or nut). Gasket for plastic is unnotched and unbuffed with armor set back from tip and must not be interchanged with regular armored gasket.

4. Install lock insert into plastic pipe. Lock insert is designed to have a friction fit in plastic pipe and may require light blows of a hammer. To prevent bending or damaging flange, use a block of wood as surface to hammer insert in place (Fig. 4). Mark pipe 2" from end. Stab plastic pipe into coupling or fitting body approximately 2".

5. Tighten nut while holding body from rotating (Fig. 5). Recommended torque for plastic end is 75 lbs. on end of wrench of size specified below.

Nominal Pipe Size	Wrench Size
¾"	14
1"	18
1-¼"	18
1-½"	24
2"	24

(Continued)

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DRESSER INDUSTRIES INC.
Bradford, Pennsylvania 16701

FORM NO. 776

DATE 12/78

Figure L-8 (Cont'd)

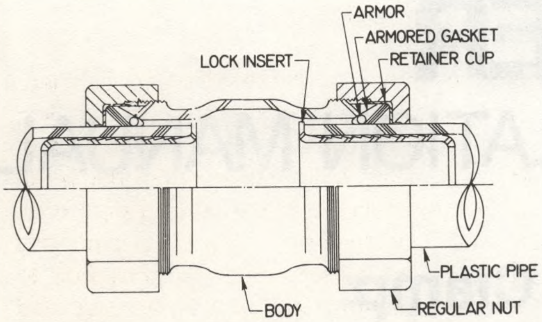
DRESSER

GAS PRODUCT INSTALLATION MANUAL

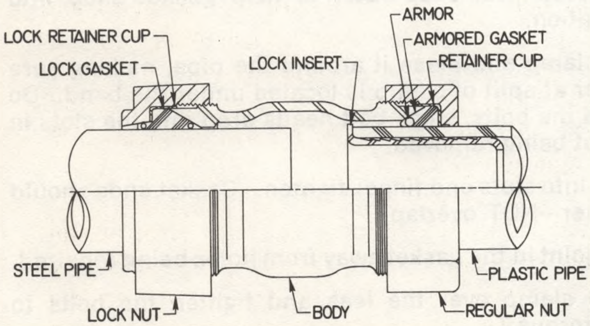
Style 90 Couplings and Fittings with "PLASTI-LOK"™ Compression Ends for PP & SP

Continued

SAMPLE



PLASTIC TO PLASTIC



STEEL TO PLASTIC

II. Steel Pipe End:

1. Clean pipe end and remove metal burr, loose scale, rust or dirt that would affect the sealing ability of gasket for not less than 3" from pipe end. Apply soapy water to gasket (ethylene gylcol may be added in freezing weather).

2. Loosen nut about one-quarter turn and relieve gasket with fingers. Make chalk mark 2½" from end of pipe. Then stab pipe end into coupling approximately 2½".

3. Tighten nut while holding body from rotating. Recommended torque for steel pipe end with ball-lock is 100 lbs. of pull on end of wrench, size specified below:

Nominal Pipe Size	Wrench Size
¾"	14
1"	18
1-¼"	18
1-½"	24
2"	24

IMPORTANT -- Coupling or fittings must be used with all parts as furnished from the factory and installed on pipe end as designated by markings on the coupling. Transition couplings and fittings from steel to plastic must be equipped with Dresser ball lock gasket and nut on steel pipe, Dresser lock insert must be used with polyethylene pipe of the SDR as designated on the body or flange of the insert.

Note: All operators must follow the specific manufacturer's instructions for the compression coupling which they are installing.

dmd DRESSER
DRESSER MANUFACTURING DIVISION
DRESSER INDUSTRIES INC.
Bradford, Pennsylvania 16701

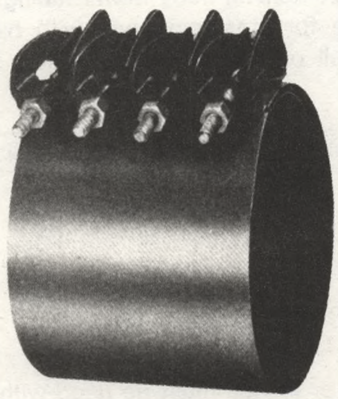
DATE 12/78

Figure L-9 REPAIR CLAMPS

These are simple repair clamps which are useful in repairing small underground corrosion leaks.

DRESSER
GAS PRODUCT INSTALLATION MANUAL

Style 130 Repair Clamp

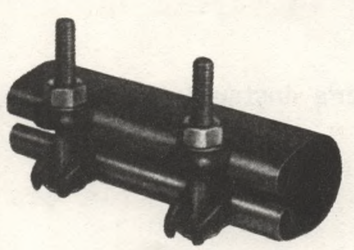


1. DO NOT CUT GASKET—IT IS CORRECT LENGTH AND WIDTH.
2. Clean pipe thoroughly where gasket is to seat. Smooth any rough spots.
3. Lubricate pipe with soap-water to help gasket slide into correct position.
4. Open the clamp and place it around the pipe, making sure the spanner at split of clamp is located under the band. Do not remove the bolts, since bolt heads drop into the slots in lugs without being removed.
5. Hook bolts into slots and finger-tighten. Gasket ends should butt together—NOT overlap.
6. Locate the joint in the gasket away from holes being repaired.
7. Center the clamp over the leak and tighten the bolts to 50 ft. lbs. torque.

SAMPLE

Note: When pipe movement out of the clamp might occur, proper anchorage of the pipe must be provided.

Style 118 HANDIBAND® Repair Clamp



1. Clean pipe thoroughly where gasket is to seat.
2. Lubricate gasket and cleaned area of pipe with soap-water (ethylene glycol should be added in freezing weather).
3. Place clamp around pipe with gasket centered over leak. Hook bolt head in slotted lug and tighten the nut.

APPENDIX M

UNACCOUNTED-FOR GAS

The term unaccounted-for gas does not always mean a leak. Leakage is only one of a number of factors contributing to unaccounted-for gas. There are seventeen or more conditions that will reflect on the unaccounted-for gas. For a given gas leak, each system will be affected differently by these conditions because there are no two systems exactly the same as to piping and customer mix.

Unaccounted-for gas is the difference between the amount of gas purchased and the quantity of gas sold, whether it be more or less.

The causes for unaccounted-for gas can be grouped into two categories. One is leaks and the other, gas measurement. Both are very broad terms. Leaks will be defined as gas escaping to the atmosphere at a given rate at an unknown location. The rate the gas escapes will only be affected by the pressure and the gradual increase of the hole size. Normally, the gas leakage will be at a fairly constant rate and will increase gradually with time if not located and repaired.

Gas lost through measurement or the lack of measurement is very deceptive and at times very difficult to detect. Gas measurement will be defined as the accounting of all gas bought and sold. Although the seventeen or more different problems contributing to unaccounted-for gas can be defined, only the ones most responsible for gas loss will be discussed.

Let's start with the gas purchase station. This station is normally owned and maintained by the seller of the gas to the gas utility and is normally termed a gate station. Very few small utilities have check meters to monitor the accuracy of these gate stations to assure an accurate amount of gas being measured. Therefore our gas accounting is always compared to their measurements. It is important to know what size cubic foot of gas is being purchased. Normally the gas volume at a gate station is corrected to a temperature of 60°F at a base pressure of 4 oz. If the gas being sold is not corrected to the same conditions we will have unaccounted-for gas.

Let's see how temperature can affect our accuracy. The purchased gas volume was calculated 60°F. At what temperature is the gas being sold? Naturally the ambient temperature affects the gas temperature. The amount of the affect is determined by the depth of the pipeline in the ground. The deeper the pipe, the more insulation the ground offers and the closer the gas temperature will be to 60°F. If the gas mains and services are above ground

or close to the surface we can be sure the gas temperature is relatively close to the air temperature on any given day.

Using round figures for every 5°F above or below 60°F, the gas volume will change by 1%. This may not sound like much, however if the average winter temperature for a three month period is 30°F, 6% unaccounted-for gas can be expected for this period. This loss can only be corrected by the use of temperature compensated meters. No temperature multiplier can be used to correct the volume unless a temperature volume instrument is used on the sales meter. Gas utilities sell the majority of their gas during the winter months so the small amount of gas sold during the hot summer will offset the losses.

How does metering pressure affect unaccounted-for gas? Remember, we are buying our gas at a 4 oz. pressure or at least the volume is corrected to 4 oz. As the pressure increases above the 4oz. base the volume of gas becomes smaller. For every 2 oz. change above the 4 oz. there is an expected loss of about 1%. Therefore, if the service regulators are delivering 8 oz. gas through the meters, approximately 2% unaccounted-for can be expected and 3% for 10 oz. Pressure compensated indexes are not normally used for domestic house meters, however they are available for the large commercial and industrial meters. If a pressure compensated index is used, care must be taken to assure the meter pressure is the same as the index pressure. The pressure compensated index will only correct for a constant pressure.

Pressure and temperature error in gas measurement are second only to leaks as a contributing factor to unaccounted-for gas. By calculating unaccounted-for gas as a percentage of the total gas purchased, it can be determined whether the loss is due to leaks or gas measurement.

If all the loss is due to leaks there will be a higher percentage of unaccounted-for gas during the summer months. The percentage due to leaks may be slightly higher in the winter if the gas system pressure is raised, however it will normally not be that noticeable. Gas loss due to pressure differences will, if the pressure at the meter is the same in the summer and winter, show the same percentage of unaccounted-for gas throughout the entire year.

Loss due to temperatures will show a higher percentage during the cold months and can be the most costly next to leaks. In summary, if the percent of unaccounted-for gas is up during the summer months look for leaks. If it increases during the winter months look for measurements errors, probably caused by temperatures.

There are many other causes for unaccounted-for gas, one being inaccurate gas meters. To determine the overall accuracy effect of the meters take a random sample of meters of all ages and in-

test them. By averaging the accuracy of the sample meters the overall accuracy of the distribution system can be determined. Taking the average of the meters brought in during a changeout period will only indicate the accuracy of the meters that have been out for a long period of time. If the overall accuracy is poor, it may indicate that the changeout period should be shortened to improve accuracy.

Gas theft, bad meters or dead meters will normally show up in the monthly billing so always be on the lookout for unexplained reductions in gas usage for a particuar customer. Remember, comparison along with an alert meter reader is the best tool available for detecting gas thefts. The hardest theft to detect is when only a small amount of gas is stolen each month. This can be accomplished by reversing the meter in the line for a few days a month or with a meter bypass. The thief in some cases is nearly impossible to catch unless elaborate means are taken to seal the meter, the meter nuts, sto-cocks, regulators and other related equipment. The old adage "If there is a will, there is a way" applies to the gas thief.

Unaccounted-for gas is a serious problem. By taking a positive approach the majority of the causes can be determined and corrected. The first 90% is the easiest to find. The remaining 10% will be a problem.

APPENDIX N

INSTRUCTIONS FOR COMPLETING FORM RSPA F 7100.1
INCIDENT REPORT - GAS DISTRIBUTION SYSTEM

GENERAL INSTRUCTIONS

Each operator of a gas distribution system, except those exempted in §191.9(c), shall file Form RSPA F 7100.1 for any incident which meets the criteria specified in §191.5 as soon as practicable but not more than 30 days following the occurrence of the incident.

Reports should be made to the: Information Systems Manager (DMT-63), Materials Transportation Bureau, Department of Transportation, 400 Seventh Street, S.W., Washington, D.C. 20590. However, reports for intrastate pipelines subject to the jurisdiction of a State agency pursuant to certification under Section 5(a) of the Natural Gas Pipeline Safety Act of 1968 may be submitted in duplicate to the State agency if the regulations of that agency require submission of these reports and provide for further transmittal of one copy within 10 days of receipt after the incident has occurred to the: Information Systems Manager (DMT-63), Materials Transportation Bureau.

Type or print the operator name and address data in the appropriate location, including the name of the branch or subsidiary, if different, where the incident occurred.

If you have any questions concerning this report or these instructions, or if you need copies of Form RSPA F 7100.1 or the instructions, please write or call the Information Systems Manager (DMT-63), Materials Transportation Bureau, Department of Transportation, 400 Seventh Street, S.W., Washington, D.C. 20590, telephone number (202) 472-1024.

For the purpose of completing Form RSPA F 7100.1, the following definitions of terms are to be used when filing Form RSPA F 7100.1 in conjunction with these instructions:

1. Gas distribution line -

   A pipeline other than a gathering or transmission line.

2. Pipeline -

   All parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached

to the pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

3. Operator -

A person who engages in the transportation of gas.

SPECIAL INSTRUCTIONS

An entry should be made in each block for which data are available. In blocks requiring numbers, all blocks should be filled in using zeroes when appropriate. When decimal points are required, the decimal point should be placed in a separate block.

Examples: (Part 4.3) Nominal Pipe Size / 0 / 0 / 2 / 4 / inches

/ 1 / . / 2 / 5 / inches

Wall Thickness / . / 5 / 0 / 0 / inches

/ . / 1 / 4 / 5 / inches

Avoid "Unknown" entries if possible. Estimated data are preferable to unknown data. If "Unknown" or estimated data entries are made, a supplemental report should follow if the data should become known by the operator.

If "Other" is checked in any part of the report, include an explanation or description on the line adjacent to the item checked.

SPECIFIC INSTRUCTIONS

Part 1

The operator's five digit identification number will be assigned by RSPA. If the identification number is not available to the person completing the report, this information should be omitted. Address in Part 1.1.C is address of office originating incident report.

Data on the location of the incident should be as complete as possible, including the nearest city or town, the county or parish, township, borough, etc. Use data that would help orientation with a map and provide such other location information as may be available. The class location should be the class location at the incident

site following as closely as possible these designations as excerpted from §192.5 of the gas pipeline safety standards.

§192.5 Class locations.

(a) Offshore is Class 1 location. The Class location onshore is determined by applying the criteria set forth in this section: The class location unit is an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. Except as provided in paragraphs (d)(2) and (f) of this section, the class location is determined by the buildings in the class location unit. For the purposes of this section, each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(b) A Class 1 location is any class location unit that has 10 or less buildings intended for human occupancy.

(c) A Class 2 location is any class location unit that has more than 10 but less than 46 buildings intended for human occupancy.

(d) A Class 3 location is—

(1) Any class location unit that has 46 or more buildings intended for human occupancy; or

(2) An area where the pipeline lies within 100 yards of any of the following:

(i) A building that is occupied by 20 or more persons during normal use.

(ii) A small, well-defined outside area that is occupied by 20 or more persons during normal use, such as a playground, recreation area, outdoor theater, or other place of public assembly.

(e) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

1.3

The time of the incident should be indicated in reference to a 24-hour clock.

Examples 1. (0000) = midnight = / 0 / 0 / 0 / 0 /

2. (0800) = 8:00 a.m. = / 0 / 8 / 0 / 0 /

3. (1200) = Noon = / 1 / 2 / 0 / 0 /

4. (1715) = 5:15 p.m. = / 1 / 7 / 1 / 5 /

5. (2200) = 10:00 p.m. = / 2 / 2 / 0 / 0 /

1.4

In-patient hospitalization means admission and confinement in a hospital beyond treatment administered in an emergency room or out-patient clinic in which confinement does not occur. The property damage/loss estimate is the estimate of total property damage or loss to the operator's property, the property of others, or the combination of both. Loss of gas is a property loss.

Check "Supplemental Report" if this is a follow-up report with additional or corrected information. Do not fill in any previously submitted information with the exception of "report date," "operator's name," "address," and "preparer." Submit only amended, revised, or added information.

1.5

Elapsed time until the area was made safe means the elapsed time from the time of the occurrence of the incident until the incident is brought under control so that it does not present a significant threat to public safety. This does not necessarily mean that the flow of gas has been stopped completely. If the time of occurrence is unknown, the time when the operator is first notified or made aware of the incident may be utilized.

Part 2

Definition of Causes

1. Corrosion - Escape of gas resulting from a hole in the pipeline or component caused by galvanic, stray current, or other corrosive action.

2. Outside Force-Third Party/Outside Party - Damage directly attributed to the striking of a gas pipeline facility caused by earth moving equipment, other equipment, tools, vehicles, vandalism, etc. Damage is by personnel other than those working for the operator or the contractor working for the operator.

3. Outside Force-Natural Forces - Damage resulting from earth movement not caused by man, including earthquakes, washouts, land slides, frost, etc. Also included is damage by lightning, ice, snow, etc.

4. <u>Accidently Caused by Operator</u> - Damage resulting from an inappropriate procedure, or a wrong application of a procedure by the operator's employee or the employee of a contractor working for the operator.

5. <u>Construction Defect/Operating Error</u> - A "construction defect" is one resulting from failure of original sound material that is due to outside force being applied during field construction which caused a dent, gouge, excessive stress, or other defect which resulted in subsequent failure. Also include faulty wrinkle bends, faulty field welds, and damage sustained in transportation to the construction or fabrication site.

6. <u>Other</u> - A cause that cannot be identified clearly as belonging in one of the above categories.

If the "Other" block is checked, the narrative in Part 3 should describe the incident in detail, including the known or presumed cause.

<u>Part 3</u>

The narrative is needed only when it is useful to clarify or explain unusual conditions. It should be a concise description of the incident, including the probable cause and conditions which the operator believes may have contributed either directly or indirectly to the cause of the incident. Explanations of estimated data also may be included in the narrative.

<u>Part 4</u>

4.1

Meter Set Assembly is the piping installed to connect the inlet side of the meter to the gas service line and to connect the outlet side of the meter to the customer's fuel line. A service regulator should be included under "2. Component which failed."

4.2

Insert type of joint (other than a weld), such as mechanical, compression, threaded, or fusion.

For a weld joint, check "weld" and specify type.

4.3

For "other," state copper, aluminum, wrought iron, etc.

4.4

This applies to all items in 4.3 and, where appropriate, to items in 4.2. In the event that more than one item has failed, so that origin is not clear, use Part D to complete 4.4 for the additional item(s).

The specification, when known, is the specification to which the pipe or component was manufactured, such as API 5L, ASTM A106, ANSI A21.9, etc. A list of referenced specifications is shown in the Appendix to 49 CFR Part 192. If the pipe or component predates 49 CFR Part 192, and was manufactured under a specification not listed in 49 CFR Part 192, put in, when known, the specification to which the pipe or component was manufactured.

Answer all questions for all pipe or components. If not available, mark "N/A."

Year installed means the year of installation at incident location.

<u>Part 5</u>

More than one box can be checked with an indication as to which box is the most appropriate environmental description.

"Under pavement" includes under streets, sidewalks, paved roads, parking lots, shopping centers, etc.

<u>Part 6</u>

"Preparer" is the name of the person most knowledgeable about the information submitted in the report or the person to be contacted for additional information.

"Authorized Signature" may be the "preparer" or an officer or other person whom the operator has designated to review and sign reports of this nature.

<u>Part A</u>

A.5

"Under cathodic protection" means cathodic protection in accordance with the requirements for Part 192 as determined by the criteria in Part 192, Appendix D. If the operator determines the cause of the corrosion to be bacterial or chemical action or stray current, check "Other" in item 3, and indicate the cause.

For the purpose of this report, galvanized pipe with no dielectric coating is to be considered "bare."

Part B

B.1

"Outside Party" (third party) means other than the operator or his agent. Acts of vandalism should be included here.

B.2.a

"Prior notification" means that the operator had been notified that excavation or construction work was to be done in the vicinity of the pipeline prior to the time the incident occurred.

B.3

Additional information, if any, should include a description of other steps taken by the operator to protect the facility against damage by outside forces. A description of an act of vandalism may be included here.

Part C

Definitions:

1. Poor Workmanship-During Construction - Wrong mechanical application of the correct procedure.

2. Operating Procedure Inappropriate - Wrong procedure was used for this application.

3. Error in Procedure Application - Misinterpretation of procedure during field application.

4. Physical Damage During Construction - Construction activity damage to existing or newly installed facilities, such as a gouge or dent, misalignment, or improper support, caused by the operator's personnel or the operator's contractor.

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NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $1,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $200,000 as provided in 49 USC 1678.

Form Approved OMB No. 2137-0522

U.S. Department of Transportation
Research and Special Programs Administration

INCIDENT REPORT — GAS DISTRIBUTION SYSTEM

Report Date ______
No. ______ (RSPA)

PART 1 — GENERAL REPORT INFORMATION

SEE INSTRUCTIONS

1. a. Operator's 5 digit Identification No. /_/_/_/_/_/
   b. Name of Operator ______
   c. ______ Number and Street
   d. ______ City, County, State and Zip Code
2. Location of Incident
   a. ______ Number and Street
   b. ______ City and County
   c. ______ State and Zip Code
   d. Class Location ☐ 1 ☐ 2 ☐ 3 ☐ 4
   e. Incident on Federal Land ☐ Yes ☐ No
3. Time and Date of Incident
   /_/_/_/_/ hour /_/_/ mo /_/_/ day /_/_/ yr
4. Reason for Reporting
   - ☐ Fatality — Number /_/_/_/ persons
   - ☐ Injury requiring inpatient hospitalization — Number /_/_/_/ persons
   - ☐ Property damage/loss — Estimate $ ______
   - ☐ Operator Judgment/Emergency Action
   - ☐ Supplemental Report
5. Elapsed time until area was made safe /_/_/ hr /_/_/ mn
6. Telephonic Report: /_/_/ mo /_/_/ day /_/_/ yr
7. a. Estimated pressure at point and time of incident *(PSIG)* ______
   b. Maximum allowable operating pressure *(MAOP) (PSIG)* ______
   c. MAOP established by:
      (1) Test pressure ______ *(PSIG)*
      (2) 49 CFR §192.619(a)(3) ☐

PART 2 — APPARENT CAUSE

- ☐ Corrosion *(Continue in Part A)*
- ☐ Damage by Outside Forces *(Continue in Part B)*
- ☐ Construction/Operating Error *(Continue in Part C)*
- ☐ Other ______
- ☐ Accidently caused by operator *(Continue in Parts B and/or C)*

PART 3 — NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE INCIDENT

(Attach additional sheet(s) as necessary)

PART 4 — ORIGIN OF THE INCIDENT

1. Part of System Where Incident Occurred
   - ☐ Main
   - ☐ Service Line
   - ☐ Meter Set Assembly
   - ☐ Other ______
2. Component Which Failed
   a. Part
   - ☐ Body of Pipe
   - ☐ Joint, type ______
   - ☐ Fitting
   - ☐ Drip/Riser
   - ☐ Valve
   - ☐ Regulator/meter
   - ☐ Weld, specify girth, longitudinal, fillet
   - ☐ Other ______
3. Material Involved:
   - ☐ Steel
   - ☐ Polyethylene plastic
   - ☐ Other ______
   - ☐ Cast iron
   - ☐ Other plastic: ______

   NPS *(Nominal Pipe Size)* /_/_/_/_/ in. Wall Thickness /_/_/_/_/ in.
4. Specification ______ Manufacturer ______ Year Manufactured /_/_/_/_/ Year installed /_/_/_/_/

PART 5 — ENVIRONMENT

Area of Incident

- ☐ Within/Under Building
- ☐ Under Pavement
- ☐ Above Ground
- ☐ Under Ground or Under Water
- ☐ Other ______

PART 6 — PREPARER AND AUTHORIZED SIGNATURE

______ (type or print) Preparer's Name and Title

______ / ______ Telephone Number

______ Authorized Signature and Date

______ / ______ Telephone Number

Form RSPA F 7100.1 (3-84)

PART A – CORROSION

1. Where did the corrosion occur?
   - ☐ Internally
   - ☐ Externally

2. Visual Description
   - ☐ Localized Pitting
   - ☐ General Corrosion
   - ☐ Other ____________

3. Cause
   - ☐ Galvanic
   - ☐ Other ____________

4. Pipe Coating Information
   ☐ Bare ☐ Coated

5. Was corroded part of pipeline considered to be under cathodic protection prior to discovering incident?
   - ☐ Yes Year protection started /__/__/__/__/
   - ☐ No

6. Additional Information

PART B – DAMAGE BY OUTSIDE FORCES

1. Primary Cause of Incident
   - ☐ Damage resulted from action of operator or his agent
   - ☐ Damage resulted from action by outside party/third party
   - ☐ Damage by earth movement
     - ☐ Subsidence
     - ☐ Landslide/Washout
     - ☐ Frost
     - ☐ Other ____________
   - ☐ Damage by lightning or fire

2. Locating information (for damage resulting from action of outside party/third party)
   a. Did operator get prior notification that equipment would be used in the area?
      - ☐ Yes Date received /__/__/ mo /__/__/ day /__/__/ yr
      - ☐ No

   b. Was pipeline location marked either as a result of notification or by markers already in place?
      - ☐ Yes ☐ Permanent Markers ☐ Temporary Stakes ☐ Other ____________
      - ☐ No

   c. Does Statute or ordinance require the outside party to determine whether underground facility(ies) exist?
      - ☐ Yes
      - ☐ No

3. Additional Information

PART C – CONSTRUCTION DEFECT

1. Cause
   - ☐ Poor Workmanship during Construction
   - ☐ Operating Procedure Inappropriate
   - ☐ Error in Operating Procedure Application
   - ☐ Physical Damage During Construction
   - ☐ Other ____________

2. Additional Information

PART D – OTHER

Brief Description:

U.S. Department
of Transportation

**Research and
Special Programs
Administration**

400 Seventh St., S.W.
Washington, D.C. 20590